PUBLIC (REDACTED) VERSION

**BEFORE THE
PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA**

**DOCKET NO. 2019-224-E
DOCKET NO. 2019-225-E**

In the Matter of:	)	
	)	**REBUTTAL TESTIMONY OF**
South Carolina Energy Freedom Act	)	**GLEN A. SNIDER**
(House Bill 3659) Proceeding Related to	)	**ON BEHALF OF DUKE ENERGY**
S.C. Code Ann. Section 58-37-40 and	)	**CAROLINAS, LLC AND DUKE**
Integrated Resource Plans for Duke	)	**ENERGY PROGRESS, LLC**
Energy Carolinas, LLC and Duke Energy	)	
Progress, LLC	)	
	)	

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I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Glen A. Snider**.** My business address is 526 South Church Street, Charlotte, North Carolina 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am currently employed by Duke Energy as Director of Carolinas Integrated Resource Planning and Analytics.

Q. DID YOU PREVIOUSLY FILE DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. The purpose of my Rebuttal Testimony is to address the policy and technical arguments raised by the Office of Regulatory Staff ("ORS"); as well as Carolinas Clean Energy Business Association ("CCEBA");[1] South Carolina Coastal Conservation League, Southern Alliance for Clean Energy, Upstate Forever, Sierra Club, and Natural Resources Defense Council (together, the "Environmental Parties"); and Vote Solar regarding Duke Energy Carolinas, LLC's ("DEC") and Duke Energy Progress, LLC's ("DEP") (together, the "Companies") integrated resource plans ("IRP") prepared pursuant to the requirements of the South Carolina Energy Freedom Act (H.3659), S.C. Code Ann. Section 58-37-40 *et seq*, as filed in

[1] The CCEBA testimony to which I am responding was filed originally filed by the South Carolina Solar Business Association ("SCSBA"). On March 10, 2021, the Commission issued Order No. 2021-167 and granted a Motion to substitute CCEBA for SCSBA as party of record in these dockets.

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these dockets on September 1, 2020 ("2020 IRPs"). Specifically, my Rebuttal Testimony responds to the Direct Testimony of ORS Witnesses Anthony M. Sandonato, Stephen J. Baron, Philip Hayet, and Lane Kollen, as well as CCEBA Witnesses Kevin Lucas and Arne Olson, Environmental Parties Witnesses James F. Wilson and Jim Grevatt, and Vote Solar Witness Tyler Fitch. For reasons I discuss further herein, I refer jointly to CCEBA, the Environmental Parties, and Vote Solar as the "Advocacy Groups."

Q. BEFORE PRESENTING YOUR REBUTTAL TESTIMONY TO THE COMMISSION, CAN YOU PLEASE PROVIDE AN OVERVIEW OF OTHER WITNESSES PROVIDING REBUTTAL TESTIMONY ON BEHALF OF THE COMPANIES?

A. The Companies' other witnesses filing rebuttal testimony in these proceedings are:

1) **Dawn Santoianni**, State Energy Policy Director for North Carolina. Witness Santoianni responds to Vote Solar Witness Fitch and explains (1) it is generally the role of state and federal policymakers—not regulated utilities—to set climate change standards; and (2) in another docket, the Companies have already agreed with Vote Solar to study climate change and risk. Witness Santoianni also explains that Witness Fitch's and CCEBA Witness Lucas's recommendation to consider fundamental regulatory and market design changes, such as studying energy imbalance markets ("EIM") or regional transmission organizations ("RTO") are legislative issues beyond the scope of these 2020 IRP proceedings.

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2) **Sammy Roberts**, General Manager, Transmission Planning and Operations Strategy. Witness Roberts responds to arguments and testimony put forward by CCEBA Witness Lucas and Vote Solar Witness Fitch, and addresses their unreasonably narrow focus on risks associated with fossil fueled generation and explains that neither of these Advocacy Group witnesses demonstrate the understanding nor recognize the fundamental importance of ensuring "power supply reliability" as the Companies plan to significantly transition their fleets, including integrating more solar generation into the DEC and DEP Balancing Authorities over the next 15-year planning period, as presented in the Companies' 2020 IRPs.

3) **Nick Wintermantel**, Principal Consultant and Partner at Astrapé Consulting, a consulting firm that provides expertise in resource planning and resource adequacy to utilities across the United States and internationally. Witness Wintermantel responds to testimony from ORS, CCEBA Witness Arne Olson, and SACE/CCL Witness Wilson regarding the Resource Adequacy Study and the Storage ELCC Study, which Astrapé conducted for the Companies.

4) **Matt Kalemba**, Director of Distributed Energy Technologies Planning & Forecasting. Witness Kalemba responds to testimony from ORS, CCEBA Witness Lucas, and CCEBA Witness Olson regarding the Companies' inputs and assumptions used for renewable energy, including energy storage.

5) **Jim Herndon**, Vice President of Strategy and Planning Practice for Nexant, an expert consulting firm hired by the Companies to evaluate and determine the potential energy and demand savings that could be achieved by energy

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efficiency ("EE") and demand-side management ("DSM") programs implemented by the Companies, an evaluation that resulted in the Market Potential Study. Witness Herndon responds to critiques of the DSM/EE Market Potential Study in Environmental Parties Witness Grevatt's testimony, and corrects the flaws and misunderstandings upon which Mr. Grevatt's opinions are based.

6) **Brian Bak**, Manager, DSM Analytics. Witness Bak also responds to testimony filed by Mr. Grevatt, focusing on the relationship between the flaws in Mr. Grevatt's analysis and the impact of those flaws on both the IRPs and on the Companies' duty to ensure reliable service to customers.

7) **Mark Oliver**, Vice President, Integrated System Planning. As leader of the Integrated System Planning group, which includes, Integrated System & Operations Planning ("ISOP"), Witness Oliver responds to certain assertions and recommendations made by Tyler Fitch, witness for Vote Solar, related to ISOP.

8) **Leon Brunson**, Lead Load Forecast Analyst. Witness Brunson responds to testimony filed by the other parties and explains how 2020 data shows that peak demand for DEP came in as expected, in spite of the pandemic, and that peak demand for DEC was 2.9% above expectations. Witness Brunson also explains and corrects other witnesses' analytical errors as related to the load forecast.

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Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANIES' REBUTTAL CASE IN RESPONSE TO THE DIRECT TESTIMONY FILED BY OTHER PARTIES IN THESE PROCEEDINGS.

A. The 2020 IRPs represent the most reasonable and prudent means of meeting our customers' energy and capacity needs under a variety of conditions that could be experienced in the future. Consistent with Act 62, DEC's and DEP's 2020 IRPs appropriately balance resource adequacy and power supply reliability, customer affordability, regulatory compliance, commodity price risk, and plan for diversity of both supply-side and demand-side resources. The Companies' six long-term resource planning portfolios meet these requirements and the optionality of the portfolios will enable the Companies to meet their unique obligation to continually, affordably, and reliably serve load.

Unlike the Advocacy Group intervenors to these proceedings, the objective of ORS is to represent the public interest. While ORS presents numerous recommendations for the Companies to "improve" the IRPs—recommendations that are fulsomely addressed in the Companies' rebuttal testimony—ORS concluded that the Companies have provided the information required by S.C. Code Ann. § 58-37-40(B)(1).[2] In response to ORS's recommendations, the Companies are providing information requested by ORS in their witness's rebuttal testimony in a good-faith effort to satisfy ORS's recommendations to the largest extent practicable. The extensive reports by ORS's consultant, J. Kennedy and

[2] ORS Sandonato Direct Exhibit AMS-1 and Exhibit AMS-2, at 16 ("ORS Reports").

Associates, Inc. ("Kennedy Associates"), also generally find the central elements and analyses of the 2020 IRPs to be reasonable and developed with "a high level of methodological sophistication."[3] And, importantly, the ORS Reports "concluded that DEC [and DEP] conducted a thorough IRP evaluation" and did not identify the same deficiencies previously identified in the DESC IRP Order.[4]

In the Companies' view, the Advocacy Groups have injected a fair amount of "noise" in their testimony that is well outside the scope of these proceedings, as prescribed by Act 62. Some Advocacy Group witnesses raise issues that are actually entirely outside of the Commission's jurisdiction (*e.g.*, advocating that the IRP proceedings should be used to study climate risk, or as wholesale power market forums to discuss fundamental regulatory and market design changes, such as studying energy imbalance markets ("EIM") or regional transmission organizations ("RTO"), or to require the Companies and their customers to pay for other parties' litigation costs, etc.). The Advocacy Groups' intent to distract from the relevant issues is obvious and should not diminish the clear and relevant fact that the Companies' 2020 IRPs are extremely robust, are sensitive to reliability and customer affordability, are reflective of substantial stakeholder feedback and are consistent with the requirements of Act 62.

The Companies would respectfully urge the Commission to exercise caution in considering whether to require modifications be made to these 2020 IRPs

[3] *Id.* at 25.
[4] *See* ORS Report (DEC), at 20; ORS Report (DEP), at 20, referencing Order No. 2020-832, *In re South Carolina Energy Freedom Act (House Bill 3659) Proceeding Related to S.C. Code Ann. Section 58-37-40 and Integrated Resource Plans for Dominion Energy South Carolina, Incorporated*, Docket No. 2019-226-E (2020) ("DESC IRP Order").

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that will not materially inform the analysis required by Act 62 as such studies may unnecessarily add costs for customers and administrative burden for ORS and the Commission; this is an especially important consideration given that the Companies' IRP updates will be filed *in approximately three months* from the date of the Commission's order in these dockets, and the Companies' next comprehensive IRP will be filed *in approximately 14 months* from the order required in these dockets. Adjustments to the Companies' IRPs can much more readily and cost-effectively be made on a going-forward basis, which is why the Companies make significant efforts to respond to all 25 of the ORS's recommendations.

The Companies are in the midst of an unprecedented, long-term transition from a legacy fleet that included coal generation towards a new mix of cleaner generation, including renewables, battery storage systems and efficient natural gas across the Companies' systems. While this is the Companies' first IRP proceeding under Act 62, this transition is necessarily a marathon, not a sprint, and the Companies and the Commission must prudently and judiciously plan for and execute this transition in a way that protects system reliability and customer affordability. Every portfolio and every resource carries risk, and only the Companies' objectively- and holistically-developed resource plans adequately address such risks. Some parties would have the Commission disavow natural gas generation without acknowledging, much less fairly considering, the Companies' obligations to comply with NERC Reliability Standards and to satisfy Act 62's requirement to appropriately balance power supply reliability and customer costs in the IRP.

In light of the long-term energy transition that is underway, some amount of flexibility in system planning will be necessary to ensure that the Companies are both meeting the reliability needs of the system and also prioritizing customer affordability. These priorities of operational reliability and customer affordability do not appear to be shared by the Advocacy Groups, which instead advocate for or against specific technologies, depending upon the mission of the organizations they represent. A unbalanced and unproven resource mix resulting from biases in system planning could have critical consequences for customers. Recent experiences in Texas and California underscore the importance of keeping all reasonable generation and infrastructure options on the table and available to customers, particularly during this time of energy transition.

The Companies' rebuttal case also emphasizes that the Commission will have a continuing opportunity to review the Companies' planning through annual IRP updates and comprehensive future filings, and will serve as a gatekeeper for resource investments through the certificating process provided by the Utility Facility Siting and Environmental Protection Act, S.C. Code Ann. § 58-33-10, *et seq*. There is no doubt that future technologies and future policy enacted by state and federal lawmakers will influence future IRPs; however, the Companies are confident that the filed IRPs meet the requirements of Act 62 and protect customers' interests in the most reasonable and prudent manner.

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Q. DOES YOUR SUMMARY OR TESTIMONY ADDRESS ALL ISSUES IN THIS CASE?

A. No. My rebuttal testimony addresses only the matters discussed below in my testimony summary below. The Companies' rebuttal witnesses address additional topics on a case-by-case basis.

Q. ARE YOU SPONSORING ANY EXHIBITS WITH YOUR TESTIMONY?

A. Yes. I am sponsoring Snider Rebuttal Exhibits 1-18. These exhibits were prepared by me or at my direction and under my supervision.

II. <u>REBUTTAL TESTIMONY</u>

Q. PLEASE BRIEFLY SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. My rebuttal testimony addresses the following**:**

General Observations on ORS and Advocacy Groups' Testimony

1) Highlights how ORS and their technical consultants, Kennedy Associates, have undertaken a reasonable, technically objective and holistic review of the 2020 IRPs' compliance with Act 62.

2) Points out how Advocacy Groups CCEBA, Vote Solar, and the Environmental Parties fail to advance technically-objective arguments and fail to approach the IRPs from a holistic view. Instead, these Advocacy Groups present one-sided arguments to advance their own interests, which generally include a nearly singular focus on expanding the deployment of solar, battery storage and DSM and EE as the "preferred plan" for DEC and DEP to meet customers' future capacity and energy needs with little consideration of power supply reliability or customer cost;

DEC/DEP 2020 IRPs Comply with Act 62

3) Demonstrates how the Companies' 2020 IRPs fully comply with filing requirements of Act 62, as confirmed by ORS, and explain how the Companies are either responding to each of ORS's 25 recommendations in rebuttal testimony, or alternatively, plan to do so through the Companies' September 2021 IRP update or next comprehensive IRPs to be filed in September 2022. Modified 2020 IRPs are neither necessary or appropriate;

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4) Explains that the Commission should review the Companies' 2020 IRPs as a "snapshot in time," to be updated in the near future. The Commission took this principled position in the 2019 Avoided Cost Dockets under Act 62, and it is appropriate to adopt again here.

5) Reemphasize that the 2020 IRPs present a total plan to the Commission, which is the most reasonable and prudent means of meeting DEC's and DEP's customers' energy and capacity needs and is compliant with Act 62

6) Explains the continued importance of considering least cost principles under Act 62 and why CCEBA Witness Lucas is incorrect that Act 62 requires the Companies to present a preferred portfolio versus the total plan of portfolios presented in the 2020 IRPs;

DEC/DEP 2020 IRPs Should be Reviewed on Own Merits

7) Requests that the Commission reject CCEBA's and Vote Solar's arguments that the Commission should rely upon findings and factual determinations made in Order No. 2020-832, ruling on Dominion Energy South Carolina's ("DESC") 2020 IRP, and, instead, review the inputs, assumptions, and methodologies used in DEC's and DEP's 2020 IRPs on their own merits;

Rebuttal/Responses on Technical Issues, Recommendation and Arguments

8) Explains that the Companies' reasonably modeled the likelihood of extreme cold events, rebutting Environmental Parties' Witness Wilson's testimony to the contrary;

9) Explains that the Companies appropriately provide sensitivity analyses and employed a reasonable methodology to model future natural gas costs using actual market-based pricing for the first 10 years (2021-2030) and then gradually transitioning to a 100% fundamentals-based forecasting approach, and the Companies agree to discuss their natural gas price forecasting methodology with ORS and others in a stakeholder process before filing their next comprehensive IRPs;;

10) Rebuts CCEBA Witness Lucas' arguments regarding the accuracy and appropriateness of relying upon nearer-term forward market-based pricing for natural gas and emphasizes the approximate $170 million over-payment obligation realized in 2020 and the longer-term $2 billion over-payment risk for consumers associated with inaccurate avoided cost assumptions due to unreasonably-high historical reliance on fundamental forecasts of natural gas pricing, which has demonstrably proven to be less accurate than market pricing since 2017;

11) Explains that Vote Solar Witness Fitch's analysis in the Carbon Stranding and Climate Risk Report should be rejected as inaccurate and mis-informed about

the cost and role of natural gas as a bridge in the Companies' net-zero carbon goals;

12) Explains that Witness Fitch's analysis of purported stranded natural gas assets inflates the risks of meeting load growth and improperly minimizes the benefits of natural gas, including affordability and reliability.

13) Explains that the optimization model employed by the Companies' did not under-value that attributes of solar and batteries;

14) Explains that how the Companies model a generic solar resource option as an energy-only resource, while rejecting recommendations to model a 20-year fixed solar PPA as creating an unfair "apples-to-oranges" comparison among generation resource options in the models;

15) Explains how the Companies prioritize winter planning, including the potential for extreme cold events, to appropriately address winter peak loads;

16) Transparently describes its diverse fleet of generating units and projects the likely longevity of operating such resources into the future;

17) Explains how the Companies' 2020 IRPs extensively analyze coal retirements, as previously required by the NCUC, and commits to engage with the ORS to discuss this modeling methodology prior to filing the Companies' next comprehensive IRPs in 2022.

Other Issues Raised in By Intervenor Testimony

18) Agree to ORS's recommendation to report on the Companies' future participation in the SEEM and rebuts CCEBA's and Vote Solar's advocacy to require the Companies to study fundamental market reforms, such as joining an EIM or RTO; and

19) Explains that there is no reasonable basis for Witness Fitch's recommendation that the Companies should acquire and pay for intervenor licenses to use the Companies' capacity expansion and production cost modeling software and this directive from the DESC Order should not be applied to DEC and DEP.

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III. GENERAL OBSERVATIONS ON ORS/ADVOCACY GROUPS' TESTIMONY AND DEC AND DEP 2020 IRPS' COMPLIANCE WITH ACT 62

(A) ORS and Advocacy Groups' Testimony Should be Viewed Through a Technically Objective and Holistic Lens

Q. CAN YOU PROVIDE AN OVERVIEW OF THE FACTORS YOU WERE LOOKING FOR AS YOU REVIEWED ORS AND INTERVENOR TESTIMONY IN THIS PROCEEDING?

A. Yes. Essentially, a resource plan must ensure the reliable supply of power while balancing affordability, environmental considerations and other factors such as diversity of generation supply. As stated in Act 62, the Companies, as electrical utilities providing service in South Carolina, are responsible for presenting a plan that balances these factors by considering multiple portfolios along with various input sensitivities outlined in the Act.[5] Act 62 directs the Commission to consider whether the Companies' IRPs "appropriately balance" factors including resource adequacy, consumer affordability and least cost; compliance with environmental regulations; power supply reliability; commodity price risks; diversity of generation supply; and other foreseeable conditions the Commission finds in the public interest.[6] In my review of testimony presented in this proceeding, I was assessing the technical objectivity and the holistic nature of intervenors' alternative recommendations as it relates to what the Commission is charged with reviewing under the Act.

[5] S.C. Code Ann. § 58-37-40(a).
[6] S.C. Code Ann. § 58-37-40(C)(2).

Q. CAN YOU FURTHER EXPLAIN WHAT YOU MEAN WHEN YOU SAY ISSUES RAISED SHOULD BE REVIEWED FOR TECHNICAL OBJECTIVITY?

A. Yes. When I speak of technical objectivity, I am referring to the merits of the assumptions, the quality of analysis and the veracity of the conclusions reached when addressing a specific issue. I, and other DEC/DEP witnesses in this case, raise several concerns with the technical objectivity of some of the criticisms raised by intervening parties—primarily those of the Advocacy Groups—while agreeing with the merits of other recommendations.

Q. NOW CAN YOU FURTHER EXPLAIN WHAT YOU MEAN WHEN YOU SAY ISSUES RAISED BY INTERVENORS SHOULD ALSO BE VIEWED FROM A HOLISTIC LENS?

A. Yes. All resources in an IRP have inherent benefits and risks across four general "focus areas" of system reliability, consumer affordability, environmental considerations as well as other longer-term factors outlined in Act 62. Consider my Figure 1 below.

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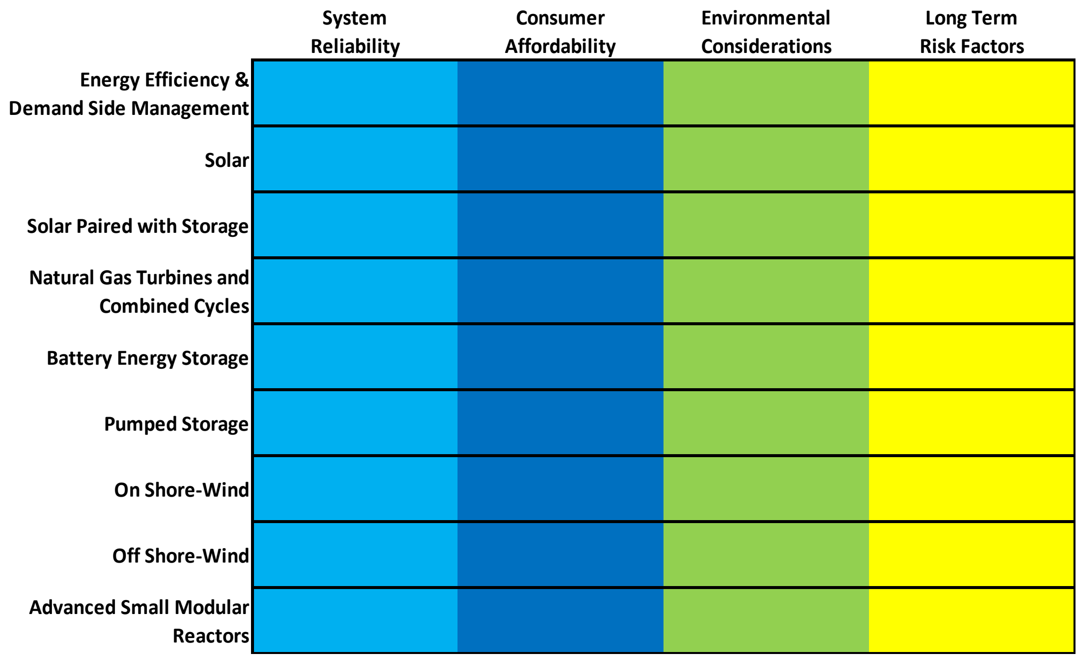
Snider Rebuttal Figure 1: Holistic Considerations for IRPs



Intervenors often raise concerns or emphasize risks or benefits that exist in only one box in the grid. However, when reviewing narrow criticisms raised by intervenors in these IRP dockets, it is important to always view the issue from a broader holistic lens. First, a holistic horizontal perspective considers the issue in the context of the collective pros and cons in each of the four focus areas for a given technology or portfolio. Second, a holistic review would also take a vertical perspective that attempts to fairly evaluate the same issue or concern raised for each of the resource alternatives in the Companies' IRPs.

Q. TO ILLUSTRATE THIS POINT, CAN YOU PROVIDE THE COMMISSION A BRIEF EXAMPLE OF AN ISSUE RAISED THAT LACKS TECHNICAL OBJECTIVITY AND, FAIRLY, SHOULD BE ASSESSED THROUGH A MORE HOLISTIC LENS?

A. Certainly. As I will address in much more detail later in my testimony, Vote Solar Witness Fitch presents a considerable amount of testimony raising the potential for stranded cost risk associated with new natural gas-fired resources, which the Companies included in five of the Companies' six long-term resource portfolios (portfolio option 6 has been included at stakeholders' request and includes no new gas assets). My testimony will address the technical soundness of his arguments and point out the errors in his assumptions, analysis and conclusions reached. My testimony will also address the holistic deficiencies of Mr. Fitch's Carbon Stranding: Climate Risk and Stranded Assets in Duke's Integrated Resource Plans ("Carbon Stranding and Climate Risk Report").[7]

My Figure 2 below demonstrates how Mr. Fitch's entire Carbon Stranding and Climate Risk Report, while voluminous, has an extraordinarily narrow view in the context of resource planning as described in Act 62. From this more holistic perspective, it can readily be seen that the study completely ignores the potential benefits of natural gas resources in the 2020 IRP portfolios that allows for the reliable and affordable replacement of retiring significant coal-fired (and carbon-emitting) capacity. He further neglects to mention that the Companies' national leading coal retirement plans paired with the IRP's renewable resources and natural

[7] Vote Solar Fitch Direct, at Exhibit TF-2.

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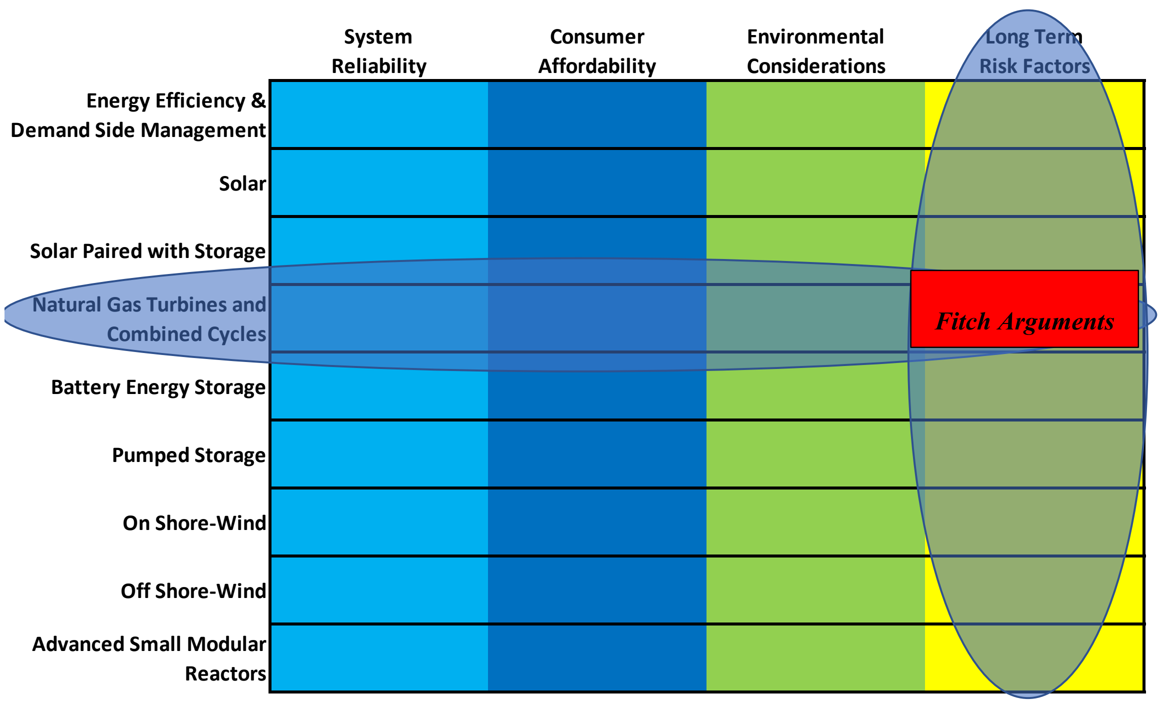
gas resources provide a balanced solution that is both reliable and results in one of the lowest carbon intense energy systems in the nation. Finally, from a vertical perspective, Witness Fitch fails to consider the same potential cost risk for other resources such as existing solar resources and emerging battery storage resources which I and other Company witnesses address in greater depth throughout our collective rebuttal testimony. In summary, this process of assessing technical objectivity of the issue while also holistically considering the horizontal and vertical implications of an issue provides important context for the Commission in its determination of the reasonableness of the 2020 IRPs, as well as the "alternatives to the plan[s]" presented by intervening parties.

Snider Rebuttal Figure 2:
Singular Focus of Fitch's Opposition to Natural Gas



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Q. WHAT ARE YOUR GENERAL OBSERVATIONS OF ORS AND INTERVENOR TESTIMONY IN THIS PROCEEDING?

A. The ORS has the unique role in representing the public interest by providing a balanced assessment of the reasonableness of these varying assumptions as it pertains to the requirements in Act 62 and the impact assumptions and results may have on consumers. As I discuss further below, the ORS is generally supportive that the Companies have met the requirements of Act 62 and many of the ORS's recommendations are reasonable.

On the other hand, the other intervenors, which I refer to collectively as the Advocacy Groups in my testimony, do not have a similar mandate as ORS. These Advocacy Groups approach the IRP proceedings with their own agendas, purposes and biases, which do not include pursuing least cost planning and ensuring power supply reliability to meet load, as addressed by DEC/DEP Witness Roberts.

The Advocacy Groups' critiques of the IRPs appear to isolate and argue for certain input assumptions in a manner that advances specific outcomes, while ignoring other data sources and risks that do not support their desired outcomes. Based on these analyses, their conclusions seem designed to advance their own interests. Based upon my review of their testimony, those interest generally include a nearly singular focus on expanding the deployment of solar, battery storage and DSM/EE programs as the "preferred plan" for DEC and DEP to meet customers' future capacity and energy needs.

The Advocacy Groups also seek to advance policy objectives and outcomes within these dockets and the resource planning process versus following the lead of state and federal policymakers who will need to make important decisions about South Carolina's and the nation's energy future as explained by DEC/DEP Witness Santoianni. This is understandable, as every intervenor has an organizationally driven view of the future of energy. The interests and goals of the Advocacy Groups are not irrelevant to this discussion, but they must be considered in the holistic context of the ultimate resource planning responsibility of a regulated electric utility. As such, the Commission should carefully scrutinize any alternative planning recommendation with the same critical lens it applies to the Companies' filing.

Q. WHAT IS THE COMPANIES' GOAL IN THIS PROCEEDING?

A. The Companies' goal is the same as the General Assembly in enacting Act 62: to provide the "the most reasonable and prudent means of meeting [DEC's and DEP's] energy and capacity needs."[8] It is critical for the Commission to keep in mind that DEC and DEP are the only parties to these dockets that are regulated by federal and state law to ensure customers in South Carolina and North Carolina receive reliable power at just and reasonable rates. As an industry leader focused on comprehensively and holistically understanding the capabilities, costs and risks of emerging technologies, the Companies strongly support the further development of solar resources, battery storage and DSM/EE programs. However, I am concerned that the Advocacy Groups' singular focus on increasing the deployment of these resources often omits the key considerations of system reliability and affordability. Recent reliability events in California in 2020 and Texas in 2021 poignantly

[8] S.C. Code Ann. § 58-37-40(C)(2).

underscore the importance of resource planning in ensuring system reliability and the value of maintaining a diverse resource mix. Extreme winter weather events in the Carolinas during the polar vortex events of 2014, 2015 and the cold weather event of 2018 also illustrate that the Carolinas can be exposed to multi-day events that stress system reliability at a time when customers depend on their power the most.

In sum, I recognize that the issues presented in the Companies' 2020 IRPs and raised by intervening parties are multi-faceted and complex, and I would respectfully recommend the Commission critically assess the technical objectivity of "alternatives to the plan[s]" presented by intervening parties and undertake a holistic view of the 2020 IRPs when balancing the factors and considerations prescribed in Act 62.

(B) <u>DEC and DEP 2020 IRPs Comply with Act 62's Requirements</u>

Q. PLEASE REINTRODUCE THE SUBJECTS THAT ACT 62 REQUIRES THE COMPANIES TO ADDRESS IN THEIR IRPs.

A. As generally discussed in my direct testimony, Section 58-37-40(B) identifies nine discrete topics that must be included in an electrical utility's IRP:

> (a) a long-term forecast of the utility's sales and peak demand under various reasonable scenarios;
> (b) the type of generation technology proposed for a generation facility contained in the plan and the proposed capacity of the generation facility, including fuel cost sensitivities under various reasonable scenarios;
> (c) projected energy purchased or produced by the utility from a renewable energy resource;
> (d) a summary of the electrical transmission investments planned by the utility;
> (e) several resource portfolios developed with the purpose of fairly evaluating the range of demand-side, supply-side, storage, and other

technologies and services available to meet the utility's service obligations. Such portfolios and evaluations must include an evaluation of low, medium, and high cases for the adoption of renewable energy and cogeneration, energy efficiency, and demand response measures, including consideration of the following:
(i) customer energy efficiency and demand response programs;
(ii) facility retirement assumptions; and
(iii)sensitivity analyses related to fuel costs, environmental regulations, and other uncertainties or risks;

(f) data regarding the utility's current generation portfolio, including the age, licensing status, and remaining estimated life of operation for each facility in the portfolio;

(g) plans for meeting current and future capacity needs with the cost estimates for all proposed resource portfolios in the plan;

(h) an analysis of the cost and reliability impacts of all reasonable options available to meet projected energy and capacity needs; and

(i) a forecast of the utility's peak demand, details regarding the amount of peak demand reduction the utility expects to achieve, and the actions the utility proposes to take in order to achieve that peak demand reduction.[9]

As highlighted in the filed 2020 IRPs and in my direct testimony, both DEC and DEP robustly address each of these topics.

1. <u>ORS finds the 2020 IRPs Fully Comply with Section 58-37-40(B)</u>

Q. DOES ORS TAKE THE POSITION THAT THE COMPANIES' IRPs COMPLY WITH SECTION 58-37-40(B)?

A. Yes. To evaluate the Companies' IRPs, ORS retained the services of Kennedy Associates, an economic consulting firm specializing in the electric, natural gas, and water industries. ORS Witnesses Baron, Hayet, and Kollen, each of Kennedy Associates, analyzed the Companies' respective 2020 IRPs in the context of the criteria set forth in Section 58-37-40(B). The ORS Reports walk through each requirement specified by Act 62 and address in some detail how DEC's and DEP's

[9] S.C. Code Ann. § 58-37-40(B)(1)(a)-(i).

respective 2020 IRPs comply with each and every section specified by the General Assembly in Act 62.[10]

2. <u>The Companies are Responding to Each of ORS's Recommendations to Demonstrate Compliance with Section 58-37-40(C)</u>

Q. PLEASE REINTRODUCE THE STANDARD UNDER WHICH ACT 62 REQUIRES THE COMMISSION TO REVIEW THE COMPANIES' IRPS.

A. Section 58-37-40(C) instructs the Commission to determine whether an IRP is "the most reasonable and prudent means of meeting energy and capacity needs[.]" In making that determination, Section 58-37-40(C)(2) provides that the Commission should consider whether the IRP appropriately balances a variety of factors, including:

(a) resource adequacy and capacity to serve anticipated peak electrical load, and applicable planning reserve margins;
(b) consumer affordability and least cost;
(c) compliance with applicable state and federal environmental regulations;
(d) power supply reliability;
(e) commodity price risks;
(f) diversity of generation supply; and
(g) other foreseeable conditions that the commission determines to be for the public interest.[11]

Q. DOES ORS TAKE THE POSITION THAT THE COMPANIES' 2020 IRPs SHOULD BE APPROVED UNDER SECTION 58-37-40(C)?

A. Not, as filed. ORS Witness Sandonato finds that "there are improvements that could be made to DEC's [and DEP's] IRP[s,]" and recommends the Companies modify certain aspects of their IRPs to provide additional information to aid the

[11] S.C. Code Ann. 58-37-40(C)(2)(a)-(g).

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Commission in its determination of whether to approve the Companies' IRPs pursuant to the requirements of Act 62. In nearly all instances, the Companies accept (and constructively respond herein) to ORS's recommendations and have either addressed these issues in the testimony being filed today or propose to address them in a future IRP Update or in the Companies' next biennial IRP filings in 2022.

While the ORS does not necessarily give a final stamp of approval to the Companies' IRPs, as filed, ORS also does not take the position that the Commission should reject the Companies' IRPs, and, in only limited instances, recommends the Companies' underlying analyses and assumptions be modified. Moreover, ORS Witness Sandonato and especially Kennedy Associates' ORS Reports comment very favorably on the Companies' IRPs and, importantly, find that "[w]ith regard to the items that the Commission discussed in the DESC order, based on the [ORS's] evaluation of [DEC's and DEP's] IRP[s], ORS concluded that DEC [and DEP] conducted a thorough IRP evaluation."[12]

In short, the Companies believe nearly all of the recommendations for additional information and improvement identified by ORS can be worked through efficiently as part of the Companies' ongoing resource planning process without the administrative burden and costs associated with a modified IRP filing.

[12] *See* ORS Report (DEC), at 20; ORS Report (DEP), at 20.

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Q. CAN YOU HIGHLIGHT ASPECTS OF THE COMPANIES' 2020 IRPs THAT ORS SPECIFICALLY FINDS TO BE REASONABLE?

A. The ORS Reports highlight numerous areas where the Companies supplied detailed, reasonable, and sophisticated analysis to support their 2020 IRPs, as well as where ORS and Kennedy Associates determined the Companies' IRPs to be compliant with Act 62:

- ORS accepted the Companies' load and energy forecasts as reasonable and representing a "high level of methodological sophistication";[13]
- ORS accepted the Companies' Resource Adequacy studies and analyses as reasonable and noted the "significant modeling enhancement," when including regional weather patterns into DEC's and DEP's ability to import energy from neighbors in extreme weather events and is reasonable and "represent a high level of methodological sophistication";[14]
- ORS accepted the Companies' natural gas forecasts finding that they were not unreasonable or "outliers" when compared to other natural gas price forecasts of other recent utilities and industry forecasts;[15]
- ORS determined that the Companies' CO_2 price forecasts track reasonably well with other proposals, U.S. Energy Information Administration ("EIA") assumptions and are higher than the average of other publicly available utility

[13] *See* ORS Report (DEC), at 22, 30; ORS Report (DEP), at 22, 30.
[14] *See* ORS Report (DEC), at 42; ORS Report (DEP), at 41.
[15] *See* ORS Report (DEC), at 49; ORS Report (DEP), at 49.

forecasts, noting the risk adjusted option for the Base Case No Carbon Policy scenario.[16]

- ORS commented that the inclusion of Customer Bill Impacts, which was not required by Act 62, "provides the Commission important information regarding the real-world impact of both the timing and magnitude of rate increases resulting from each of the Portfolios"[17]
- With respect to stakeholder engagement, ORS comments that the Companies "have gathered, documented, and incorporated stakeholder feedback into the IRP process across a breadth of subjects"[18]

Q. OVERALL, DOES ORS FIND THE COMPANIES' 2020 IRPs TO BE THE MOST REASONABLE AND PRUDENT OPTIONS TO MEET THE COMPANIES' ENERGY AND CAPACITY NEEDS AT THIS TIME?

A. While the ORS does not explicitly state this, we read the ORS testimony and ORS Reports as providing strong support for the Companies' 2020 IRPs being reasonable and prudent and meeting the requirements of Act 62.

The ORS concluded that the Companies "conducted a thorough IRP evaluation" and "relied on industry standard approaches" in developing their IRPs.[19] When discussing conclusions of the Companies' resource planning, Kennedy Associates, wrote:

> "The Company's six portfolios demonstrate that the Company has identified a broad range of demand-side, supply-side, storage and other technologies, as required by Act 62. The portfolios allow for

[16] *See* ORS Report (DEC), at 55, 56; ORS Report (DEP), at 55, 56.
[17] *See* ORS Report (DEC), at 93; ORS Report (DEP), at 92.
[18] *See* ORS Report (DEC), at 97; ORS Report (DEP), at 96.
[19] *See* ORS Report (DEC), at 20; ORS Report (DEP), at 20.

> consideration of different coal retirement schedules, renewables, advanced technologies, and aggressive CO2 targets. In addition, the Company conducted a reasonable set of sensitivity analyses."[20]

Kennedy Associates goes on to highlight the Companies' economic evaluation of portfolios and sensitivities:

> "The Company's analysis is detailed and provides reasonable quantifications of the costs for each Portfolio and each sensitivity for planning purposes based on the Portfolios and sensitivities that were studied and given the assumptions utilized to model the existing resources, especially fuel, variable operation and maintenance expenses, and purchased power expenses and operating performance existing and new resources in PROSYM; capital costs of existing coal-fired resources subject to retirement; transmission capital costs necessary if existing coal-fired resources are retired; and capital costs, fixed operating expenses, transmission infrastructure costs, and other assumptions necessary to model new generic resource additions."[21]

These comments along with the testimony of ORS's Witnesses support the reasonableness and prudence of the Companies' 2020 IRPs.

Q. HOW DO THE COMPANIES RESPOND TO THE ORS'S RECOMMENDATIONS DESCRIBED BY WITNESS SANDONATO AND PRESENTED IN THE ORS REPORTS TO DEMONSTRATE TO THE COMMISSION THAT THEIR 2020 IRPs MEET THE REQUIREMENTS OF ACT 62?

A. As noted above, the vast majority of the ORS's recommendations are designed to provide the Commission with additional information and justification for certain inputs and analysis and to "improve" the Companies' IRPs. Similar to the stakeholder engagement that the Companies undertook prior to filing their IRPs,

[20] *See* ORS Report (DEC), at 83; ORS Report (DEP), at 82.
[21] *See* ORS Report (DEC), at 86; ORS Report (DEP), at 85.

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the Companies believe it is important to continue considering and incorporating reasonable feedback and recommendations to improve their IRPs and the presentation of the underlying analysis. To that end, the Companies have worked diligently to either address the ORS recommendations in the testimony being filed today or propose how to address the recommendations in future IRPs.

As my Figure 3 details, the Companies are addressing 16 of the ORS's 25 recommendations in rebuttal testimony and will engage with ORS to ensure these issues are appropriately addressed in future IRPs, if applicable, at the time of filing. The Companies are also proposing to address an additional seven of the remaining nine ORS recommendations in future IRPs or future IRP discovery. Finally, the Companies respond to the remaining three recommendations and explain why the Companies do not support those recommendations as written and offer responsive testimony to address these recommendations.

Snider Rebuttal Figure 3: Summary of DEC/DEP Responses to ORS Recommendations

ORS Recommendation	Company Response
Information Provided in Testimony	
4 – Solar Capacity Value Study Explanation of how study was used to derive solar capacity value	Provided response in Kalemba testimony
5 – EE/DSM Justification for values in Portfolio A	Provided as Exhibit 11 to Snider testimony
9 – Unit Costs Tables with environmental capital and O&M	Provided as Exhibit 10 to Snider testimony
10 – Data Inputs Cross reference table for inputs for models and LCR table	Provided as Exhibit 6 to Snider testimony
11 – Nuclear Relicensing Additional info on plans	Provided as Exhibit 7 to Snider testimony
12 – Bad Creek Relicensing Status on plans	Provided response in Snider testimony
13 – Allen Unit Retirements (DEC Only) Additional clarification on plans	Provided as Exhibit 17 in Snider testimony

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13 – Darlington Unit Retirements (DEP Only) Additional Clarification on plans	Provided as Exhibit 15 to Snider testimony
14 – Sequential Peaker Method Best method for coal retirement analysis	Provided response in Snider testimony
15 – CHP CHP treatment in models	Provided as Exhibit 16 to Snider testimony
16 – CT Capital Costs Justification for cost	Provided as Exhibit 9 to Snider testimony
17 – Battery Storage Justification for O&M and capacity factors	Provided response in Kalemba (O&M) and Snider (CF) testimony
19 – Solar and Solar + Storage Capacity Values Review assumptions in stakeholder process	Provided response in Kalemba testimony
20 – Renewable Resources Cross-reference table of renewable resources in IRP	Provided as Exhibit 1 in Kalemba testimony
21 – Post In-Service Capital Costs Include in PVRR calcs	Provided as Exhibit 12 to Snider testimony
24 – Short-Term Action Plan Additional information on included resources	Provided as Exhibit 14 to Snider testimony
Will Provide in Future IRPs	
1 – Load Forecast Technical Appendix for load forecast detail	Will provide in future IRP discovery
2 – Resource Adequacy Detail on methodology for synthetic loads for extreme low temps	Will provide in future Resource Adequacy studies Not appropriate as a Technical Appendix in IRP
3 – Resource Adequacy Further develop methodology for effects of extreme low temps on winter load	Will address in future IRP stakeholder process
7 – EE/DSM Additional info on development of low EE/DSM case	Will provide in future IRPs; information provided in Bak testimony
8 – Natural Gas Pricing Review methodology and consider alternates	Will address in future IRP stakeholder process
22 – Average Retail Rate Impacts Include in this IRP and future IRPs	Will provide in future IRPs
25 – SEEM Provide status and updates in future IRPs	Will provide in future IRPs
Disagree with Recommendation	
6 – EE/DSM High EE/DSM with High Fuel sensitivity	Companies disagree with recommendation; information provided in Snider testimony
18 – Solar PPA Include generic solar PPA proxy in models of $38/MWh	Companies disagree with recommendation; information provided in Snider testimony.
23 – Average Retail Rate Impacts Align methodology and assumptions with PVRR calcs	Companies disagree with recommendation; information provided in Snider testimony

My rebuttal testimony and the rebuttal testimony of other DEC/DEP witnesses provide more detailed responses on each of the issues summarized in my Figure 3.

3. The 2020 IRPs and the Companies' Stakeholder Engagement Efforts Go Above and Beyond Other Utilities' IRPs and Act 62's Requirements

Q. DOES THE COMPANIES' COMMITMENT TO PROVIDE THE ADDITIONAL INFORMATION REQUESTED BY ORS GO ABOVE AND BEYOND WHAT OTHER UTILITIES ACROSS THE COUNTRY PROVIDE IN THEIR IRPS?

A. I strongly believe so, and ORS's answers to discovery by the Companies supports this view. In assessing ORS's recommendations, the Companies asked ORS and Kennedy Associates to identify whether other State Public Service Commissions ("PSC") require, or other public utilities across the Country voluntarily provide, similar information as part of their integrated resource planning process. In over 20 instances, ORS and Kennedy Associates advised that they were not aware of other PSCs requiring (or utilities voluntarily providing) similarly detailed information.[22] I do not raise this point in objection to the provision of this additional information; rather, I want to highlight for the Commission that the level of analysis and supporting data that the Companies are committing to provide in these proceedings go well beyond industry norms for utilities in other jurisdictions.

[22] Response of South Carolina Office of Regulatory Staff to Duke Energy Progress, LLC's and Duke energy Carolinas, LLC's First Set of Requests for Production of Documents and Interrogatories, Interrogatory Nos. 1-1, 1-8 to 1-10, 1-11 to 1-17, 1-19 to 1-30.

Q. ACT 62 ALSO PROVIDES THAT THE COMPANIES' IRPs "MAY INCLUDE" CERTAIN INFORMATION SUCH AS INTEGRATED SYSTEMS OPERATION PLANS. DO THE COMPANIES VOLUNTARILY PROVIDE INFORMATION THAT IS NOT EXPRESSLY REQUIRED BY ACT 62?

A. Yes. Section (B)(2) provides that "an integrated resource plan may include distribution resource plans or integrated system operation plans." The Companies voluntarily included an update on DEC's and DEP's ongoing integrated system operations planning efforts in Chapter 15 of their 2020 IRPs, as well as conducted multiple in-depth studies well beyond the requirements of Act 62 and included them as attachments to the IRPs.

Several areas of focus in the IRPs that were not expressly mandated by Act 62 include:

- a residential average bill impact analysis for each portfolio in order to provide stakeholders with a more relatable measure of the cost tradeoffs between the portfolios;
- an energy efficiency Market Potential Study ("MPS") commissioned in order to obtain estimates of the technical, economic and achievable potential for EE savings within the DEC and DEP service territory;
- an energy storage effective load carrying capability ("ELCC") study;
- a new Resource Adequacy Study and effective load carrying capability study which were attached the IRP; and

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- an economic coal retirement study and earliest practicable coal retirement study.

Q. HAVE THE COMPANIES ALSO UNDERTAKEN SIGNIFICANT VOLUNTARY EFFORTS TO ENGAGE WITH STAKEHOLDERS ON THEIR 2020 IRPS?

A. Yes. As I highlighted in my direct testimony, the Companies went to great lengths to bring stakeholder perspectives—along with significant internal and external expertise—to bear in the production of the 2020 IRPs.[23] These efforts included:

- held multiple professionally-facilitated stakeholders meetings prior to and one after the filing of the 2020 IRPs to explain results;
- created an IRP engagement website; and
- developed a first-of-its-kind utility-supported, interactive and web enabled "Portfolio Screening Tool" accessible at https://screeningtool.duke-energy.com/ that allows stakeholders to test a portfolio over a 7-day winter, spring or summer period in DEC and DEP's service territory.

[23] DEC/DEP Snider Direct, at 35-36.

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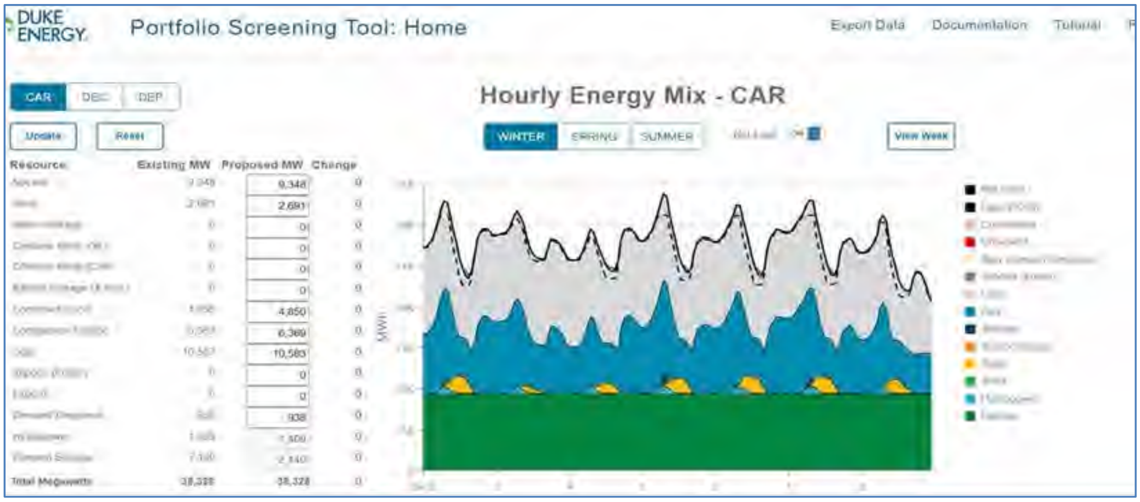
Snider Rebuttal Figure 4: DEC/DEP IRP Engagement Website Interactive Portfolio Screening Tool for Stakeholder Engagement



Links to the IRP Stakeholder Engagement website, the Portfolio Screening Tool and a visual example of the tool's capability is also provided in Snider Rebuttal Exhibit 1.

While ORS comments favorably on the Companies' stakeholder engagement[24], the Advocacy Groups— many of whom actively participated in the Companies' stakeholder processes and who then, in all cases, are hired experts from other parts of the Country—give the Companies little to no credit for these extensive stakeholder engagement efforts to provide our customers and stakeholder with information regarding our 2020 IRPs.

[24] *See* ORS Report (DEC), at 97; ORS Report (DEP), at 96.

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4. The Companies have also engaged in good faith and reasonable discovery, but have not had the same reasonable opportunity to investigate Advocacy Groups' alternative recommendations

Q. HAVE THE COMPANIES ALSO ENGAGED IN "REASONABLE DISCOVERY"[25] TO ENABLE ORS AND THE ADVOCACY GROUP INTERVENORS TO REVIEW THE 2020 IRPs?

A. Yes. Since the Commission initiated this proceeding to review the 2020 IRPs, the Companies have also provided significant information to ORS and other intervenors through the discovery process. In response to ORS and, primarily, the Advocacy Groups' requests for information, DEC and DEP have made available over 3,200 data responses providing documents, workpapers and other analytical support, utilized in developing the 2020 IRPs under review in these dockets. Notably, this included all discovery produced to intervening parties in the parallel 2020 North Carolina review of the Companies' IRPs. In addition, the Companies setup an FTP site and uploaded approximately 350 MB of data and supporting documents for the IRP and Resource Adequacy Study. Snider Rebuttal Exhibit 2 provides a summary overview of the extensive information that DEC and DEP have produced to parties in these dockets in discovery to allow for a thorough investigation of the Companies' 2020 IRPs.

In my view, the voluntary stakeholder engagement efforts along with the unprecedented amount of information produced by the Companies in these proceedings far exceeds the "reasonable discovery"[26] required under Act 62 and

[25] S.C. Code Ann. § 58-37-40(C)(1).
[26] S.C. Code Ann. § 58-37-40(C)(1).

further demonstrates the Companies' good faith efforts and willingness to engage with stakeholders to provide the most informative IRPs to the Commission for its review.

Q. HAVE THE COMPANIES HAD THE OPPORTUNITY TO REVIEW AND ANALYZE THE ADVOCACY GROUPS' ALTERNATIVE ANALYSES AND RECOMMENDATIONS TO A SIMILAR EXTENT?

A. No, and this is an important point for the Commission to appreciate**.** Act 62 recognizes that reasonable discovery applies to both the Companies' IRPs as well as "alternatives to the [IRPs] raised by intervening parties."[27] While ORS and the Advocacy Groups have had over six months to investigate DEC's and DEP's IRPs and to analyze the over 3,200 documents and data responses provided by the Companies, the Companies have had only approximately 45 days to review the hundreds of pages of alternative analyses and planning recommendations offered by intervening parties in these proceedings and even less time to review the analyses, work papers and other information provided by intervening parties in discovery.

In some cases, the Companies have not received responses to their requests for discovery because the 20-day time period for responses has not yet expired. However, in the case of CCEBA, the Companies have not received responses because CCEBA has refused to provide the information requested. CCEBA's refusal to provide discovery to the Companies has hindered the Companies' ability to review certain of their "alternative recommendations" as further addressed by

[27] S.C. Code Ann. § 58-37-40(C)(1).

Witness Wintermantel. The net effect is that ORS's and the Advocacy Groups' recommendations and analyses have not been subjected to the same rigorous review and investigation as the Companies' extensive modeling, analyses and supporting studies presented in the 2020 IRPs.

To be clear, the Companies recognize the statutory constraints prescribed by Act 62 for the Commission to review and approve the IRPs and appreciate that Act 62 imposes practical limits on the periods for testimony and discovery in these proceedings. But the Commission also should not assume that the Companies have had an equal opportunity – with regard to the amount of time and the extent of information made available – to review the Advocacy Groups' analyses and alternative recommendations.

5. <u>The 2020 IRPs are Appropriately Anchored by Least Cost Principles</u>

Q. PLEASE COMMENT ON CCEBA'S POSITION THAT SOUTH CAROLINA'S IRP STANDARD IS NO LONGER CONFINED TO LEAST COST PLANNING.

A. CCEBA Witness Lucas takes issue with the statement in the 2020 IRPs that the Companies' Base Case portfolios "employ traditional least cost planning principles as prescribed in both North Carolina and South Carolina" and argues that the Commission "is not confined to the least cost plan if more reasonable and prudent portfolios exist."[28] While I do not disagree that Act 62 now mandates the Commission "appropriately balance" the factors prescribed in Section 58-37-40(C)(2), the Companies do not see any legal or policy basis in the new Act 62

[28] CCEBA Lucas Direct, at 11.

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framework to depart from traditional least cost planning principles in developing their IRPs. The IRP statute provides a wide range of information to be provided, and consumer affordability and least cost is certainly a key consideration among that information.

There are also other important legal principles and practical considerations involved in assessing the extent to which "least cost" planning applies in South Carolina. The Commission and parties cannot ignore that the Companies' regulatory conditions, as approved by this Commission, require DEC and DEP to conduct least cost planning analyses.[29] Moreover, North Carolina law also requires it. North Carolina's Public Utilities Act specifically provides that the NCUC shall regulate DEC and DEP:

> To assure that resources necessary to meet future growth through the provision of adequate, reliable utility service include use of the entire spectrum of demand-side options, including but not limited to conservation, load management and efficiency programs, as additional sources of energy supply and/or energy demand reductions. To that end, to ***require energy planning and fixing of rates in a manner to result in the least cost mix of generation and demand-reduction measures which is achievable,*** including consideration of appropriate rewards to utilities for efficiency and conservation which decrease utility bills.[30]

[29] See Regulatory Condition 3.5 ("DEC and DEP shall retain the obligation to pursue least cost integrated resource planning for their respective Retail Native Load Customers and remain responsible for their own resource adequacy subject to Commission oversight."). The North Carolina Regulatory Conditions were approved by the North Carolina Utilities Commission in its September 29, 2016 Order Approving Merger Subject to Regulatory Conditions and Code of Conduct, in Docket Nos. E-2, Sub 1095, E-7, Sub 1100 and G-9, Sub 682. It was further adopted, as applicable to South Carolina, via the Public Service Commission of South Carolina's Order No. 2016-772 dated November 2, 2016, and as updated in a filing made on October 9, 2018.

[30] N.C. Gen. Stat. § 62-2(a)(3a).

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The Companies highlight these legal principles and other considerations for the Commission to emphasize that one key principle of the Companies' integrated resource planning process—as well as the Commission's review of the Companies' IRPs under Act 62—is to show a base case that remains grounded in traditional least cost planning principles.

6. <u>The 2020 IRPs Reasonably Present a Single Integrated Resource Plan</u>

Q. PLEASE RESPOND TO CCEBA WITNESS LUCAS'S ARGUMENT THAT THE COMPANIES' IRPs SHOULD BE REJECTED BECAUSE DEC AND DEP PRESENT MULTIPLE LONG-TERM PLANNING PATHWAYS AND DO NOT EXPLICITLY SELECT A SINGLE RESOURCE PORTFOLIO.

A. CCEBA Witness Lucas misinterprets the statutory requirements of Act 62.[31] Nothing in the IRP statute requires the Companies to pick a single preferred long-term resource planning portfolio as argued by CCEBA—and only CCEBA. To the contrary, Act 62 requires the development of multiple portfolios to fairly evaluate the range of demand side, supply side, storage, and other technologies and services available to meet the utility's service obligations.[32]

The Companies' 2020 IRPs reasonably present multiple long-term planning pathways, including a base portfolio without CO_2, which is designed to represent each utility's least cost plan under current policy assumptions and regulatory and statutory policy as it exists today, as well as a separate base case with CO_2, that relies more heavily on solar and solar plus battery storage capacity, but is also more

[31] CCEBA Lucas Direct, at 12-15.
[32] S.C. Code Ann. § 58-37-40(B)(1)(e).

heavily reliant on resource types that are commercially available today. In addition to the two base portfolios, the Companies also present four additional portfolios that achieve more aggressive carbon reduction goals than the two base portfolios and are dependent to varying degrees, on continued technological advancements, as well as supportive legislation. Chapter 14 of the Companies' 2020 IRPs also presents short-term action plans to inform the Commission (as well as the NCUC and stakeholders) on the near-term actions the Companies plan to take to reliably serve customers over the next 5 years.

Q. DO YOU VIEW THE COMPANIES' IRPs AS PRESENTING A TOTAL RESOURCE PLAN THAT IS APPROPRIATE FOR COMMISSION APPROVAL?

A. Yes. As I explain in my direct testimony, the Companies presented their IRPs as a total plan that can adapt to changing standards, technology and policy decisions in the future.[33] An update to the base portfolios in the plan will be filed later this year and a new comprehensive IRP will be developed and filed with the Commission next year. The Companies continue to believe their 2020 IRPs, as filed, are consistent with Act 62 which directs the Commission to approve the proposed integrated resource plan if it represents the most reasonable and prudent means of serving our customers' future energy and capacity needs at the time the plan was reviewed.[34] The 2020 IRPs accomplish that goal.

[33] DEC/DEP Snider Direct, at 35-36.
[34] DEC/DEP Snider Direct, at 36.

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Moreover, while CCEBA and other Advocacy Group intervenors may be advocating for specific technologies to be "preferred" over other technologies, the Companies have fairly and objectively evaluated all technologies to meet the obligation to reliably and cost effectively serve customers. Recent national experience in Texas, California and throughout the country underscores the importance of keeping all reasonable generation and infrastructure options on the table and available for customers, particularly during this time of energy transition.

I would also re-emphasize that DEC and DEP are the only entities in these dockets with the privilege and obligation to provide adequate, safe, and reliable service to our customers now and in the future. This mission makes it critical that the Companies preserve the appropriate operational capabilities and flexibility through the ongoing transitions in the industry and the Companies' own planned longer-term transitions of our own generating fleets.

Q. DO YOU AGREE WITH ORS'S ASSERTION THAT THE BASE CASE WITHOUT CARBON IS THE COMPANIES' "PREFERRED PLAN" FOR PURPOSES OF CERTAIN OTHER REGULATORY PROCEEDINGS?

A. I agree with ORS but would use the term "Appropriate Plan", which is an important and nuanced distinction for the Commission to understand. The ORS Reports sponsored by Witness Sandonato state,

> "[a]t this time, DEC [and DEP] supports the Base Case without CO_2 case as its preferred plan for purposes of avoided cost proceedings, value of solar calculations, cost-effectiveness, and DSM evaluations. It is likely that they choose this plan because 1) it reflects currents regulatory and statutory policy that is in place today, 2) it represents the least cost plan under current policy assumptions, 3) it includes a considerable amount of new renewable resources, 4) it relies on resources that are

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> commercially available today, and 5) it is a flexible plan that can easily be modified to allow more renewable resources to be added if a CO2 policy is implemented."[35]

ORS's position is based on the Companies' response to ORS AIR 3-1, which I have included as Snider Rebuttal Exhibit 3. While I agree with the enumerated statements in ORS Witness Sandonato's testimony, I would simply point out these facts do not make the Base Portfolio Without Carbon the Companies' "Preferred Plan." Rather, the Companies agrees that "at this time" it is the "Appropriate Plan" for consideration and use by the Companies in the avoided cost proceedings and other regulatory matters listed by ORS Witness Sandonato because it reflects current regulatory and statutory policies that are in place today. I also agree with the characterization of this portfolio and the benefits of the portfolio outlined in ORS's points 2 thru 5 above.

Q. HOW DO YOU RESPOND TO WITNESS LUCAS'S ASSERTION THAT, "DUKE FAILS TO PRESENT SUFFICIENT ANALYSES REQUIRED TO DETERMINE THE REASONABLENESS AND PRUDENCE OF ITS PORTFOLIOS"?[36]

A. I strongly disagree**.** The Companies' IRPs meet each and every requirement set forth in the new IRP statute under Act 62 and, as I have previously mentioned, in many respects the 2020 IRPs go well beyond the standards and requirements set forth in Act 62.

[35] *See* ORS Report (DEC), at 20-21; ORS Report (DEP), at 21.

[36] CCEBA Lucas Direct, at 17-19.

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As outlined in the Cross Reference Tables in Appendix N (DEC) and Appendix O (DEP) of the IRPs, being reproduced as Snider Rebuttal Exhibit 4, careful consideration was given during the preparation of the 2020 IRPs to comply with each individual requirement of the Act. To prepare the 2020 IRPs, the Companies dedicated tremendous amounts of internal time from subject matter experts from across the organization, as well as bringing in national experts to support the various studies presented as attachments to the IRPs. As recognized by ORS, the Companies utilized sophisticated modeling and analysis performed by individuals spanning multiple functional disciplines who collectively represent hundreds of years of industry experience.

While "reasonable and prudent" may have one meaning for CCEBA Witness Lucas, Act 62 provides specific guidance for what information is needed for the Commission to make the determination of reasonableness and prudence and I strongly support the Companies' efforts to meet and exceed the standard established in the Act.

Moreover, as I discuss further below, the Commission does not need to reject the Companies' IRPs to get additional information, as the Companies are addressing many of the ORS's requests for additional information in rebuttal testimony and DEC and DEP will each be filing an IRP update in approximately six months and full IRP in approximately 18 months.

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7. New Analyses Should be Limited to Meeting Resource Planning Objectives and Should Not Focus on Changing the Regulatory or Policy Framework in South Carolina

Q. DO YOU HAVE ANY GENERAL COMMENTS REGARDING THE ADVOCACY GROUPS' RECOMMENDATIONS FOR THE COMPANIES TO UNDERTAKE ADDITIONAL PLANNING STUDIES AND NEW PLANNING ANALYSES OR INVESTIGATIONS OF EVOLVING ENERGY REGULATORY OR POLICY ISSUES?

A. The Companies appreciate the significant interest in these 2020 IRPs, as well as the Advocacy Groups' desire for the Companies to undertake additional analytical studies, planning analyses or to investigate evolving regulatory or policy issues in future IRPs. Notable examples include Vote Solar and CCEBA witnesses attempting to have the Companies study issues that require a legislative mandate.

However, it is necessary for these parties to understand that there must be a limit to the level of IRP-targeted analysis that reasonably can (and should) be undertaken in an IRP process. No single resource plan can address every possible study area of potential interest to parties nor can it envision all possible outcomes in an evolving industry. Rather the planning process is repeated over time allowing for adaptations to inputs, changing study focus areas, as well as the incorporation of changing state and federal energy policies. Moreover, the extensive studies, analyses and system modeling used to develop the Companies' 2020 IRPs require significant Companies' resources, ORS resources, and Commission resources, which are ultimately paid for by customers. As such, it is important to ensure any additional work requested in this proceeding is meaningful to the Companies' long-term planning process and impactful to the results.

(C) <u>The 2020 IRPs Represent a "Snapshot in Time" in a Long-Term Planning Process</u>

Q. WHAT IS THE COMPANIES' PERSPECTIVE OF HOW THE COMMISSION SHOULD APPROACH THIS FIRST IRP PROCEEDING UNDER ACT 62?

A. These IRP proceedings are the Companies' first before this Commission under Act 62, and, as such, are of great importance as they will help guide the Companies' resource planning and system operations over multiple time horizons. The Commission has the difficult job of reviewing the enormous amount of information filed by the Companies, ORS, and other intervenors and providing long-term planning guidance to the Companies based upon the information before them and the requirements of Act 62. Recognizing the complex new issues presented in the 2020 IRPs and the significant amount of information before the Commission, I think it would be helpful for the Commission to consider the information presented in the 2020 IRPs as a "snapshot in time" and reflective of the best available information at the time of filing.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY THE 2020 IRPs REPRESENTING A "SNAPSHOT IN TIME."

A. Resource planning assumptions are changing constantly, and as such, the Companies' IRPs should be viewed as a dynamic document. In the current environment, many changes are occurring rapidly, on many fronts, including technology development and deployment and new laws and regulations impacting

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the long-term costs and benefits. IRP development is a nearly continuous process, and as technology evolves and future statutory, regulatory and policy developments occur, these new developments will inform future IRPs. And it is equally important for the Commission to recognize that IRPs are filed often so that the Commission (as well as the NCUC and stakeholders) can keep apprised of the Companies' future resource needs and plans to meet those needs in the future.

Focusing in on the 2020 IRPs, the Companies developed these resource plans based on inputs and assumptions generally fixed in late spring and summer months of 2020 leading up to the September submittal of the IRP. By functional necessity, the analyses, cost input assumptions, and other factors represent information that was available at that point in time prior to the time of filing.

Q. HAS THE COMMISSION PREVIOUSLY RECOGNIZED THAT THIS SNAPSHOT CONCEPT IS APPROPRIATE FOR RESOURCE PLANNING?

A. Yes. The Companies emphasized this same concept in the Commission's 2019 proceedings to review and approve DEC's and DEP's avoided costs under Act 62 ("2019 Avoided Cost Dockets"). This issue arose in the context of intervenors' advocacy to consider prospective post-filing developments that could have impacted DEC's and DEP's identified future capacity needs. In approving the Companies' avoided capacity costs based upon the then-current 2019 IRP Updates, the Commission found in Order No. 2019-881(A) that "it is necessary for the utilities to 'snap a line in chalk' at some point in time for purposes of resource planning and calculating the Companies' avoided cost rates."[37]

Q. DO ADVOCACY GROUP INTERVENORS RECOGNIZE THAT THIS RESOURCE PLANNING CONCEPT IS APPROPRIATE IN THIS PROCEEDING?

A. Just the opposite**.** As I highlight above, Advocacy Groups with specific agendas have emerged to insert doubt or disagreement with the long-term planning portfolios and extensive analysis performed to develop the Companies' 2020 IRPs. Several of their alternative planning recommendations would require the Companies to re-analyze options and to re-file a modified IRP to address more recent events that occurred after the 2020 IRPs were filed. For example, CCEBA Witness Lucas recommends that the Commission reject the 2020 IRPs and require the Companies to "update modeling to incorporate the impact of the extension of the federal [Investment Tax Credit ("ITC")] on solar and solar plus storage projects."[38] Mr. Lucas argues that that this is a "major development", suggesting "the impact on the IRP's portfolios could be large enough to warrant inclusion at this point."[39] DEC/DEP Witness Kalemba also addresses this issue and appropriately concludes the upcoming IRP updates to be filed this September will adequately capture these issues in addition to other changing inputs. He concludes

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[37] Order No. 2019-881(A) at 89, Docket Nos. 2019-185-E and 2019-186-E (Jan. 2, 2020).

[38] CCEBA Lucas Direct, at 6.

[39] CCEBA Lucas Direct, at 5.

this essentially yields a potential modified IRP filing in this docket obsolete by the time it is filed and reviewed by ORS.

Q. TO SUMMARIZE, DO YOU AGREE WITH THE ADVOCACY GROUP INTERVENORS' RECOMMENDATIONS THAT IT IS NECESSARY TO UPDATE THE 2020 IRPs TO RECOGNIZE MORE RECENT DEVELOPMENTS?

A. No. The Commission should continue to view integrated resource planning as a snapshot in time, and should recognize, as they did in the 2019 Avoided Cost Dockets, that the Companies can incorporate these more recent developments into future IRPs.

Q. DO YOU AGREE WITH ORS'S RECOMMENDATIONS THAT THE COMMISSION SHOULD REQUIRE THE COMPANIES TO FILE MODIFIED IRPs TO INCORPORATE ORS'S RECOMMENDED IMPROVEMENTS TO THE 2020 IRPs?

A. No. As I highlight above, the Companies are addressing the vast majority of ORS's recommended improvements either in rebuttal testimony or propose to do so as part of DEC's and DEP's next IRP Update or comprehensive IRP filing, as appropriate. The Companies recognize that the Commission has the authority to require DEC and DEP to file modified 2020 IRPs to incorporate these ORS recommendations within 60 days of the Commission's final order on the 2020 IRPs.[40] However, imposing this requirement would be unnecessarily burdensome on the Companies.

[40] S.C. Code Ann. § 58-37-40(C)(3).

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It would also seemingly be unduly burdensome on ORS's and the Commission's regulatory calendars as they would be required to review the modified plans from this proceeding at the same time the Company is filing its statutorily-required updated IRP in the upcoming IRP proceeding. This is a duplicative and costly approach considering the timing of the IRP update this year and the Companies' commitment to develop a full IRP next year. Finally, there is no material action identified in the Companies' short-term action plans that would benefit from a modified IRP filing in this docket as compared to an updated IRP filing occurring this September.

The Companies' view is that "re-running" the IRPs and filing modified IRPs is appropriate only where the Commission finds fundamental flaws in the utility's IRP as not compliant with Act 62. Accordingly, the Companies recommend that the Commission take note of the Companies' information provided in testimony and the Companies' commitment to work with ORS, as appropriate, to incorporate any new developments that have occurred since filing their 2020 IRPs to be addressed in the next IRP Update or full IRP filing.

Q. WHEN DO THE COMPANIES NEXT PLAN TO PROVIDE THE COMMISSION A NEW COMPREHENSIVE IRP BASED UPON A NEW "SNAPSHOT IN TIME" THAT COULD FURTHER INCORPORATE ANY DIRECTIVES ISSUED IN THIS PROCEEDING?

A. Act 62 requires the Companies to file updated IRPs with the Commission "at least every three years." However, the Companies are planning to submit their next comprehensive IRPs in September of 2022, which is consistent with the biennial

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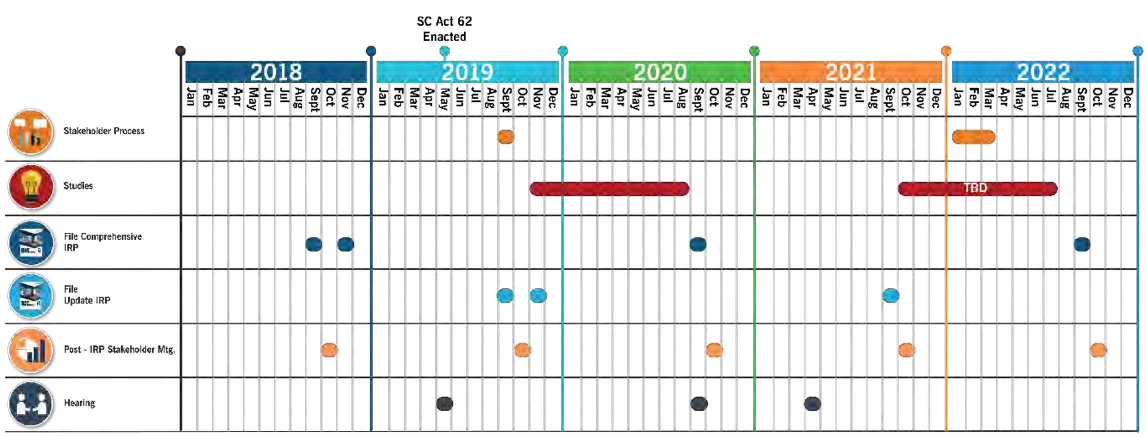
calendar for filing IRPs in the Companies' North Carolina jurisdiction. This is less than 18 months away from today and will be approximately 14 months from when the Commission issues an Order on the 2020 IRPs.

My Rebuttal Figure 5 provides the Commission a high-level schedule presenting the major milestones in the Companies' recent 2018-2020 IRPs as well as the forward-looking IRP planning process. The Companies are also providing a more detailed schedule in Snider Rebuttal Exhibit 5 of this testimony. This schedule provides major tasks in the Companies' IRP process and avoided cost planning schedules. Both schedules evidence the frequency with which the Companies will be before this Commission on these important topics. As previously alluded to, my Figure 5 below highlights the nearly continuous nature of IRP planning and highlights the pace at which changing assumptions, studies, policies and stakeholder feedback are being captured.

Snider Rebuttal Figure 5: Regulatory Timeline for IRP Development



(D) <u>DEC's and DEP's 2020 IRPs Should be Considered on their Own Merits</u>

Q. PLEASE COMMENT ON CCEBA WITNESS LUCAS'S ARGUMENTS THAT THE COMPANIES' IRPs SHOULD BE REJECTED BECAUSE THEY SHARE CHARACTERISTICS WITH DESC'S RECENTLY REJECTED 2020 IRP.[41]

A. A primary argument underpinning a number of CCEBA Witness Lucas's recommendations that the Commission should reject DEC's and DEP's 2020 IRPs is his assertion that the Companies' IRPs "share characteristics with DESC's rejected IRP." He then proceeds to identify a number of technical and factual considerations, such as energy storage cost assumptions, the addition of new energy resources or PPAs when there was not a capacity need, as well as the alleged similarities between the Companies' and DESC's natural gas forecasting methodology. While the Companies and DESC are both subject to the same IRP-related legal requirements under Act 62, it would be unfair to the Companies and unreasonable to allow the Advocacy Groups to essentially bootstrap arguments that they presented to the Commission in the DESC IRP proceeding. The Companies' witnesses are fully prepared to defend the inputs, assumptions, and methodologies used in their 2020 IRPs, and to explain to the Commission why the Companies' IRPs are appropriately the most reasonable and prudent option for our customers at this time. Simply put, the Companies' IRPs should be considered on their own

[41] CCEBA Lucas Direct, at 15-17.

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merits and the Commission should disregard CCEBA's arguments attempting to rely upon directives and factual findings in the DESC IRP proceeding.

Q. DOES ORS FIND THE COMPANIES' IRPs DEFICIENT IN THE SAME MANNER AS DESC'S IRP?[42]

A. No. The ORS Reports explain that "[w]ith regard to the items that the Commission discussed in the DESC order, based on the evaluation of [DEC's and DEP's] IRP[s], ORS concluded that DEC [and DEP] conducted a thorough IRP evaluation."[43]

IV. RESPONSES TO SPECIFIC RECOMMENDATIONS AND CRITICISMS

(A) The Companies' Load and Energy Forecasts Comply with Act 62 and are Supported by ORS

Q. PLEASE REINTRODUCE THE ACT 62 REQUIREMENTS TO ADDRESS LOAD AND ENERGY FORECASTS AS PART OF THE COMPANIES' IRPs.

A. Act 62 requires IRPs to include a long-term forecast of the utility's sales and peak demand under various reasonable scenarios.[44]

Q. DO THE COMPANIES' LOAD AND ENERGY FORECASTS MEET THE REQUIREMENTS OF ACT 62?

A. Yes, the Companies' load and energy forecasts satisfy the requirements of Section 40(B)(1)(a) of Act 62. The load and energy forecasts provide information regarding future energy and peak demand growth to inform the IRP including the type of

[42] CCEBA Lucas Direct, at 15-17.

[43] See ORS Report (DEC), at 20; ORS Report (DEP), at 20.

[44] S.C. Code Ann. 58-37-40(B)(1)(a).

generation, transmission and distribution resources needed to serve customer needs. The load forecast includes scenarios that assume more optimistic conditions and recession-like conditions compared to the base forecast. The load forecast is also a primary input in resource adequacy planning.

Q. DOES ORS SUPPORT THE COMPANIES' LOAD AND ENERGY FORECASTS, AS PRESENTED IN THE 2020 IRPs?

A. Yes. ORS determined that the forecasts meet the requirements of Act 62, are reasonable, and represent a high level of methodological sophistication.[45]

Q. DOES ORS PRESENT ANY RECOMMENDATIONS OF ISSUES TO BE ADDRESSED IN FUTURE IRPS?

A. Yes. ORS recommends the Companies provide a more comprehensive technical appendix that more fully describes each of the models, presents the statistical results and shows the individual energy and peak load forecast results that were actually developed.

Q. DO THE COMPANIES AGREE TO PROVIDE THIS INFORMATION?

A. Yes, the Companies agree to provide this information**.** ORS recognizes that DEC's and DEP's IRPs provided an overview of their modeling and statistical results and show the individual energy and peak load forecasts, but seeks for the Companies to provide "the detail necessary to fully evaluate the entire forecast" which ORS fairly notes was provided in response to discovery in this proceeding. However, due to the voluminous content of models and data associated with this request, the

[45] *See* ORS Report (DEC), at 20; ORS Report (DEP), at 22.

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Companies do not believe it is practical to include this information as an appendix to the IRP. Rather, the Companies believe that a more manageable and useful medium for ORS and stakeholder access is to continue to provide this information electronically through the discovery process.

Q. DO ANY OF THE ADVOCACY GROUPS COMMENT ON THE COMPANIES' LOAD AND ENERGY FORECASTS?

A. Yes. CCEBA Witness Lucas and Environmental Parties' Witness Wilson commented on the load and energy forecasts. DEC/DEP Witness Brunson addresses these comments in his rebuttal testimony.

(B) <u>The Companies' Resource Adequacy Study and Reserve Margins Comply with Act 62 and are Supported by ORS</u>

Q. PLEASE REINTRODUCE THE ACT 62 REQUIREMENTS TO ADDRESS RESOURCE ADEQUACY AND RESERVE MARGINS AS PART OF THE 2020 IRPs.

A. Act 62 requires the IRP to balance multiple factors including resource adequacy and capacity to serve anticipated peak electrical load, and applicable planning reserve margins.[46] Act 62 also requires the Commission to consider and appropriately balance power supply reliability.

Q. DO THE COMPANIES' RESOURCE ADEQUACY AND RESERVE MARGIN RECOMMENDATIONS MEET THE REQUIREMENTS OF ACT 62?

A. Yes. The Companies' resource adequacy and load and energy forecasts

[46] S.C. Code Ann. § 58-37-40(C)(2)(a).

appropriately balance the factors set forth in Section 58-37-40(C). DEC and DEP retained Astrapé Consulting to conduct comprehensive resource adequacy studies to determine the appropriate reserve margin for use in development of the Companies' 2020 IRPs. The Astrapé Resource Adequacy Study reports can be found as Attachment III to the Companies' IRPs.

Based on results from the various scenarios and sensitivities included in the Resource Adequacy Studies, Astrapé recommended both utilities continue to plan to a minimum 17% winter reserve margin. The Companies adopted this recommendation and included a 17% winter reserve margin in the development of their 2020 IRPs. I believe that a 17% reserve margin is reasonable and appropriate for inclusion in the 2020 IRPs, for the reasons further discussed in the direct and rebuttal testimonies of DEC/DEP Witness Nick Wintermantel of Astrapé.

Q. DOES ORS SUPPORT THE COMPANIES' RESOURCE ADEQUACY STUDIES AND RESERVE MARGINS, AS PRESENTED IN THE 2020 IRPs?

A. Yes. ORS concluded that the Company's 17% winter peak reserve margin analysis meets the requirements of Act 62, is reasonable and represents a high level of methodological sophistication.[47]

Q. DOES ORS PRESENT ANY RECOMMENDED IMPROVEMENTS REGARDING THE RESOURCE ADEQUACY STUDIES TO BE ADDRESSED IN MODIFIED OR FUTURE IRPs?

A. Yes. ORS recommends that the Companies provide a more detailed discussion of

[47] ORS Report (DEC), at 44; ORS Report (DEP), at 45.

the specific methodology used to develop the synthetic loads for extreme low temperature periods to further explain the detail regarding how the analysis was conducted or what specific additional adjustments were made to the load data at extreme low temperatures. In addition, ORS recommends the Companies further develop its methodology to model the effects of extreme low temperatures on winter peak load. Given the significance of this issue, as discussed in the ORS Reports, there may be alternative methodologies that the Companies could consider to develop its synthetic loads in hours in which the temperatures fall significantly below the temperatures experienced during the weather/load estimation period (i.e., neural net model training period). ORS recommends that the Companies should address this issue in future IRPs through the Companies' stakeholder process.[48]

Q. DO THE COMPANIES AGREE WITH ORS'S RECOMMENDATION TO PROVIDE ADDITIONAL DETAIL ON THE METHODOLOGY USED TO MODEL EXTREME LOW TEMPERATURE PERIODS?

A. Yes. The Companies agree this is a reasonable request and this information can be provided in future IRP proceedings. As noted by ORS Witness Sandonato, this additional detail was provided in response to discovery in this proceeding.[49]

[48] ORS Report (DEC), at 4; ORS Report (DEP), at 4.
[49] ORS Report (DEC), at 4; ORS Report (DEP), at 4.

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Q. DO THE COMPANIES AGREE WITH ORS'S RECOMMENDATION TO FURTHER DEVELOP THEIR METHODOLOGY FOR MODELING THE EFFECTS OF EXTREME LOW TEMPERATURES ON WINTER PEAK LOAD?

A. Yes. The Companies agree with this recommendation. As demonstrated by the extreme severe weather and corresponding challenges faced by ERCOT in Texas this winter, consideration of extreme weather events is critical to resource adequacy planning and the uncertainty in load due to extreme weather is a primary driver of the reserve margin. However, without recent data from extreme cold weather events, it is challenging to capture the impact on load at temperatures not seen in recent years.

The Companies satisfied this recommendation by conducting a stakeholder process for the 2020 resource adequacy studies. Astrapé presented the regression equations that were developed for extreme weather load modeling to stakeholders. However, participants did not suggest any changes or recommend alternative methodologies to the proposed modeling assumptions. The Companies plan to continue to analyze this important issue in developing future IRPs.

Q. ASIDE FROM THE ASTRAPÉ STUDY, DID THE COMPANIES TAKE ANY OTHER ACTION TO EVALUATE WINTER PEAK DEMAND?

A. Yes. DEC and DEP are winter planning utilities, meaning that the winter peak demand period drives the need for future resource additions. The need for winter planning is primarily driven by (i) greater load volatility during the winter, and (ii) the significant penetration of solar resources on the DEC and DEP systems. As

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noted by Witness Roberts, solar resources have a greater capacity value contribution towards meeting summer afternoon peaks, but have very little to no capacity value contribution at the time of winter peak demands which typically occur in early morning hours.[50] Accordingly, the Companies engaged nationally-recognized experts Tierra Resource Consultants in partnership with Dunsky Energy Consulting and Proctor Engineering Group to study DEC's and DEP's winter peak capacity needs and define a proposed solution set of EE/DSM customer programs and technologies that together could offer opportunities to enable the Companies to more effectively manage energy demand during winter peak periods (the "Winter Peak Study"). The Winter Peak Study was completed in December 2020, after the filing of the 2020 IRPs.

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE WINTER PEAK STUDY RESULTS.

A. The Winter Peak Study identified incremental demand reduction potential under low, mid and max scenarios. The values are incremental to current demand response program winter peak impacts. The low, mid, and max scenarios of winter potential is estimated to reach 1,079 MW, 1,273 MW and 1,378 MW respectively by 2041 for the combined Companies. For example, the mid scenario projects 766 MW in DEC and 507 MW in DEP for a total reduction of 1,273 MW by 2041.

[50] See DEC/DEP Roberts Rebuttal, at 19-20.

Q. DO ANY OF THE ADVOCACY GROUPS COMMENT ON THE COMPANIES' RESOURCE ADEQUACY PLANNING?

A. Yes. Environmental Parties Witness Wilson addresses the Companies' modeling of winter peak loads, and CCEBA Witness Olson addresses the Companies' installed capacity planning. I disagree that their alternative planning recommendations are more appropriate to ensure future resource adequacy and reliability for the reasons that follow:

1. <u>Witness Wilson's Evaluation of Winter Peak Loads Improperly Underestimates the Likely Frequency of Future Extreme Cold Events</u>

Q. PLEASE DISCUSS WITNESS WILSON'S POSITION REGARDING THE COMPANIES' STATED WINTER RESOURCE ADEQUACY RISK.

A. Witness Wilson opines that the Companies' resource adequacy studies overstated the winter resource adequacy risk for two reasons. First, he opines that the resource adequacy studies are "highly inconsistent" with the Winter Peak Study because they modeled peak loads based on extreme weather events that were significantly in excess of the peak load used in the Winter Peak Study.[51] Second, Witness Wilson criticized the Companies' reliance on 39 years of equally weighted temperature data (1980-2018) on the grounds that the approach likely overestimates the frequency of extreme cold events in the future.[52]

[51] Environmental Parties Wilson Direct, Exhibit B, at 5.

[52] Environmental Parties Wilson Direct, Exhibit B, at 5.

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Q. PLEASE EXPLAIN WHY THE COMPANIES USED HIGHER WINTER PEAK LOAD ASSUMPTIONS IN THEIR RESOURCE ADEQUACY STUDIES.

A. As I explained in my direct testimony, the Companies conduct loss of load expectation ("LOLE") studies to determine the reserve margin needed to ensure reliable service to our customers. As such, the resource adequacy studies must consider the potential for extreme weather and the associated impact on customer load.

In contrast, the Winter Peak Study was not focused on an extreme weather event, but rather examined actual data from the 2017-2018 time period, selecting a January 2018 event that reflected the highest coincident peak demand for the combined DEC and DEP system during this two-year time period. This high winter peak load event was used as the study peak day. The study examined the shape and drivers behind extreme winter events to design programs and rate solutions to reduce customer load; however, study results were not driven by the potential magnitude of an extreme winter event.

Q. WOULD USE OF A HIGHER PEAK LOAD ASSUMPTION HAVE CHANGED THE WINTER PEAK STUDY PROGRAM SOLUTION SET?

A. No. The Winter Peak Study was not specifically intended to assess forecast parameters used in the resource adequacy studies, it was used to identify EE/DSM program solutions and emerging technology opportunities that more generally offer targeted energy and demand savings on winter peak coincident end uses across all winter peak days. As such, use of a higher peak load assumption for the study peak day associated with extreme winter weather events would not have changed the Winter Peak Study program solution set.

Q. WHY DOES WITNESS WILSON BELIEVE THAT THE COMPANIES OVERESTIMATE THE LIKELIHOOD OF FUTURE EXTREME COLD EVENTS?

A. Mr. Wilson suggests that it was inappropriate for the Companies to give equal weight to 39 years of temperature data as that time span includes many instances of "very extreme cold" that have not occurred for decades in South Carolina, thus overstating the likely frequency of such events going forward.[53]

Q. HOW DO YOU RESPOND TO THIS CRITICISM?

A. DEC/DEP Witness Wintermantel of Astrapé addresses specific critiques of the Resource Adequacy Study raised by Witness Wilson and other intervenors. However, it is important to note that Witness Wilson's view on the likely frequency of future extreme cold events is at odds with a recently released Electric Power Research Institute ("EPRI") study, which found that extreme events are occurring more, not less, frequently.[54] While the extreme cold weather events experienced during the 1980s may not have reoccurred in recent decades, there is no basis to assume that such low temperatures will never occur again. The recent prolonged extreme cold event in Texas—which included record setting, sub-freezing temperatures and wind chills across the state and resultant prolonged power

[53] Environmental Parties Wilson Direct, Exhibit B, at 6.

[54] Electric Power Research Institute, Exploring the Impacts of Extreme Events, Natural Gas Fuel and Other Contingencies on Resource, at 4-2 (Jan 28, 2021), *available at* https://www.epri.com/research/products/000000003002019300.

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outages[55]—also underscores the need for utilities to plan for such exceptional events.

I would also like to note the difference in the impact on summer versus winter peak demands under extreme temperatures. Customers have the ability to supplement space heating in ways that are not available for cooling which results in much greater winter load volatility compared to summer. It is also worth noting that this risk could grow as more end uses such as water heating and space heating become electrified as the nation moves toward net-zero carbon emissions.

Q. DO YOU BELIEVE THE 2020 RESOURCE ADEQUACY STUDIES APPROPRIATELY ADDRESS POTENTIAL EXTREME WEATHER EVENTS?

A. Yes, I do. I believe the studies appropriately captured the potential impact on load due to extreme weather to determine the reserve margin required to meet the reliability standard of 1 day in 10 years LOLE and ensure the utility has enough capacity to meet customer load in all but a few extreme conditions. The Companies will periodically conduct new resource adequacy studies as more information and data becomes available to better inform the modeling and assumptions used in the study, including lessons learned from the recent cold weather event in Texas.

[55]ERCOT, Review of February 2021 Extreme Cold Weather Event – ERCOT Presentation, at 10 (Feb. 24, 2021), *available at*: http://www.ercot.com/content/wcm/key_documents_lists/225373/Urgent_Board_of_Directors_Meeting_2-24-2021.pdf.

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2. Witness Olson's Recommendation that the Companies Employ Unforced Capacity ("UCAP") Planning Reserve Margin Would Have Minimal Impact on the IRP and Selection of Resources While Requiring the Companies to Significantly Re-Design Their Planning Reserve Margin Process

Q. PLEASE DISCUSS CCEBA WITNESS OLSON'S POSITION REGARDING THE COMPANIES' PLANNING RESERVE MARGIN.

A. Witness Olson opines that renewable resources and energy storage are not appropriately accounted for in the Companies' standard installed capacity ("ICAP") planning reserve margin studies and that the Companies should instead employ a UCAP planning reserve margin.

Q. PLEASE DESCRIBE THE CONCEPTS OF A UCAP PLANNING RESERVE MARGIN AND AN ICAP PLANNING RESERVE MARGIN.

A. Installed capacity, or ICAP, and unforced capacity, or UCAP, are industry terms for tracking the capacity contributing to the planning reserve margin with UCAP used within certain RTOs. ICAP refers to the maximum amount of electricity a generator is designed to reliably produce seasonally, or what is sometimes referred to as net dependable capacity. However, despite this rating, power plants are usually not able to produce this maximum output 100% of the time due to unit forced outages or deratings. In contrast, UCAP refers to the average amount of electricity that is actually available at any given time after discounting the time that the facility is unavailable due to outages or deratings. As noted by Witness Olson on page 16 of Exhibit AO-2, "ICAP or UCAP [Planning Reserve Margins] are simply accounting conventions, so each can accurately quantify the required reserve margin to meet a reliability threshold."

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Q. PLEASE PROVIDE AN EXAMPLE OF ICAP AND UCAP.

A. Assume a generator has a seasonal net dependable capacity rating of 100 MW and an annual outage rate of 5%. For this example, the ICAP rating would be 100 MW and the UCAP rating would be 95 MW [100 MW x (1 – 5%)].

Q. DO THE COMPANIES USE AN ICAP OR UCAP PLANNING RESERVE MARGIN IN THE IRP PROCESS?

A. The 17% reserve margin resulting from the Resource Adequacy Studies and used in the 2020 IRPs reflects the installed capacity of the resource or in RTO terms using ICAP accounting. DEC and DEP have consistently used the ICAP accounting methodological approach in both North Carolina and South Carolina IRP for many years. Importantly, as seen in the recent ERCOT reliability event the forced outage rate of a unit can vary from annual averages. As explained in the Companies' resource adequacy studies, and as explained by Witness Wintermantel, the variable nature of outages is dynamically captured in the loss of load analysis rather than an after the fact accounting adjustment.

Q. WHY DOES WITNESS OLSON RECOMMEND THE USE OF A UCAP PLANNING RESERVE MARGIN?

A. Mr. Olson states that using UCAP rather than ICAP ensures that non-firm capacity and firm capacity are compared on a level playing field.[56]

[56] Olson Exhibit AO-2, at 16.

Q. DO YOU AGREE WITH MR. OLSON THAT THE COMPANIES SHOULD SWITCH TO THE UCAP PLANNING RESERVE MARGIN CONVENTION IN THE IRP PROCESS?

A. No, I do not**.** As noted by Witness Olson on page 35 of Exhibit AO-2, use of a UCAP planning reserve margin would require a significant re-design of the current planning reserve margin process. Further, and more importantly, given that new thermal resources have very low forced outage rates, converting to UCAP accounting would have very little impact on the expansion plan and the selection of resources.

(C) <u>The Companies' Natural Gas Price Forecasts are Reasonable and CCEBA Witness Lucas's Recommendation to Deviate from the Nearer-Term Market Price Should be Rejected as it Would Expose Customers to Significant Future Avoided Cost Over-Payment Risk.</u>

Q. DO THE COMPANIES' NATURAL GAS PRICE FORECASTS MEET THE REQUIREMENTS OF ACT 62?

A. Yes, the Companies' appropriately provide sensitivity analyses related to fuel costs projections, as required in Section 58-37-40(e)(iii), including providing reasonable natural gas price forecasts over the 15 year resource planning period, in order to inform the Companies' IRPs.

Q. DOES ORS ACCEPT THE COMPANIES' NATURAL GAS PRICE FORECASTS, AS PRESENTED IN THE 2020 IRPs?

A. Yes. The ORS and Kennedy Associates extensively reviewed the methodological approach to natural gas price forecasting and the Companies' resulting low, base, and high natural gas price forecast assumptions. As part of this review, the ORS and Kennedy Associates compared the Companies' natural gas price forecast

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assumptions to those assumptions utilized by six other regulated utilities, including DESC, Dominion Energy Virginia, and the Tennessee Valley Authority, amongst others, as well as performed benchmarking to natural gas forecasts in the EIA's 2020 Annual Energy Outlook ("2020 AEO").[57]

Based on this analysis, the ORS and Kennedy Associates found that the Companies' natural gas price forecasts "do not appear to be unreasonable," commenting that "the important question is whether DEP's forecasts are outliers when compared to the other forecasts, and ***the answer is no***."[58]

Q. DOES ORS PRESENT ANY RECOMMENDATIONS OF ISSUES TO BE ADDRESSED IN FUTURE IRPs?

A. Yes. The ORS Reports comment on the Companies' methodology of using market-based pricing for the first 10 years (2021-2030) and then gradually transitioning to a 100% fundamentals-based forecasting approach. ORS and Kennedy Associates correctly explain that the Companies' "market-based forecast came from a NYMEX natural gas price strip actually purchased by the Company on April 9, 2020, which the Company used as its market assumptions for 2020-2030. Beginning in 2031, the natural gas price strip was blended with a long-term fundamental natural gas price forecast that the Company obtained from its vendor, IHS Markit ("IHS"), which was referred to as the North American Natural Gas

[57] See ORS Report (DEC), at 46-47, Fn. 57-63; ORS Report (DEP), at 46-47, Fn. 57-63.

[58] See ORS Report (DEC), at 49; ORS Report (DEP), at 49 (emphasis added).

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Long-Term Outlook, February 2020. By 2035, the forecast was completely based on the IHS fundamentals forecast."[59]

In reviewing this natural gas forecasting methodology, the ORS and Kennedy Associates identify as "noticeable" that the near term forecast is rather flat for about ten years during the period that market prices are being used and also identifies concerns about the Companies' ability to lock in its gas supply for its entire system for the next ten years, which in Kennedy Associates' experience would be unusual for an electric utility to do. They also highlight the fact that even the Companies' own fuel forecast vendor, IHS, and EIA appear to have a different view of how natural gas prices will increase over time, and those two forecasts are largely consistent. The ORS Reports express some concern that relying upon an unreasonably low natural gas forecast "could result in indicating that natural gas-fired resources are comparatively less expensive than they otherwise would be relative to other resource alternatives."[60]

Accordingly, ORS and Kennedy Associates recommend the Companies review its natural gas price forecasting methodology and investigate alternative approaches to be addressed in future IRPs through the Company's stakeholder process.

Q. PLEASE COMMENT ON THE ORS'S RECOMMENDATION?

A. The ORS and Kennedy Associates present reasonable recommendations, and Duke agrees to discuss their natural gas price forecasting methodology with ORS and

[59] See ORS Report (DEC), at 46; ORS Report (DEP), at 46.

[60] See ORS Report (DEC), at 50; ORS Report (DEP), at 50.

other stakeholders between now and the next comprehensive IRP in 2022. Fuel forecasts were a focal topic in the 2020 IRP stakeholder process and the Company is committed to engaging with the ORS and other stakeholders on this topic going forward. As the Companies work with the ORS and stakeholders it will continue to assess market liquidity and volatility, and will also review varying economic price forecasts from EIA, IHS and other reputable forecasts to assess trends, similarities and differences between forecasts.

I want to reiterate that the ORS and Kennedy Associates do not find the Companies' natural gas forecasts to be unreasonable or "outliers" compared to other market information and forecasts of future natural gas prices. There is inherent "difficulty in forecasting long-range prices of natural gas, as well as other fuels...." as recently recognized by the North Carolina Public Staff.[61] This is especially true during a year like 2020 where short term natural gas markets are significantly impacted by broader economic events, such as the COVID-19 pandemic.

Finally, I also think it is important to address ORS's and Kennedy Associates limited concerns so that the Commission has a clear understanding of why the Companies have developed natural gas forecasts in the manner that they have for their IRPs in these proceedings, as well as for both avoided cost and IRP purposes in North Carolina.

[61] In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2020, Initial Statement of the Public Staff, at 41, N.C.U.C. Docket No. E-100 Sub 167 (filed Jan. 25, 2021).

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Q. PLEASE PROVIDE BACKGROUND AND CONTEXT FOR THE COMPANIES' NATURAL GAS PRICE FORECASTING METHODOLOGY RELYING UPON 10 YEARS OF ACTUAL MARKET PRICING BEFORE TRANSITIONING TO RELY UPON FUNDAMENTAL FORECASTS?

A. Over time, the Companies have increasingly relied upon market data as part of this approach as the market for natural gas has become increasingly liquid, and fundamentals forecasts have shown to be overpriced as natural gas prices continuously decline.

In the NCUC's 2014 *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities,* the NCUC found that increased reliance on forward prices for natural gas by the North Carolina public utilities in their 2014 IRPs, and on coal prices by DEC and DEP, adequately captured changing fuel market conditions, and again noted "the important relationship that exists between the biennial avoided cost proceeding and the IRP, and helps to maintain internal consistency between these proceedings," therefore directing the utilities to ensure alignment between forecasts used in their IRPs and those used in avoided costs.[62]

Again in 2016, the NCUC reiterated this focus on alignment of avoided cost forecasts with IRP forecasts and also found that "lagging fundamental forecast pricing has proven to be inaccurate over the past few years and has led to

[62] *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities,* at 27, N.C.U.C Docket No. E-100, Sub 140 (Dec. 17, 2015).

overpayment to QFs."[63] The NCUC went on to state that it was "concerned that undue reliance on higher fundamental forecast prices when a demonstrated liquid market exists can lead to arbitrage," and that "based on structural changes in the natural gas market," it was "also concerned that fundamental forecasts take significant time to develop and are only released by research firms once or twice per year."[64] In regards to overpayment risk, the NCUC found that pre-existing PURPA policies had created a "distorted marketplace" for solar QF development,[65] and ordered the Companies' to utilize eight years of market data as opposed to five years as advocated by Public Staff and certain intervenors in that avoided cost proceeding.

Most recently, in the NCUC's 2018 avoided cost order, the NCUC "again recognize[ed] the important relationship that exists between the [NCUC's] biennial avoided cost proceeding and the [NCUC's] review of IRPs, as well as the importance of maintaining internal consistency between these proceedings."[66] In doing so, the NCUC approved the Companies' calculation of their avoided energy costs using forward contract natural gas prices for eight years before using fundamental forecast data for the remaining contract period. The slight difference between eight years of market data before transitioning to fundaments in the avoided cost case and the ten years of market in the IRP is an issue that will come before the NCUC in this November's avoided cost filing. Importantly the trends

[63] *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, at 77, N.C.U.C. Docket No. E-100, Sub 148 (Oct. 11, 2017) ("N.C.U.C. Sub 148 Order").
[64] *Id.*
[65] *Id.*at 15-16.
[66] *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities,* at 58, N.C.U.C. Docket No. E-100, Sub 158 (Apr. 15, 2020).

observed in the 2014, 2016 and the 2018 dockets referenced above persist to this day.

Q. CCEBA WITNESS LUCAS SPENDS ALMOST 40 PAGES ATTEMPTING, IN HIS WORDS, TO "DECONSTRUCT" THE COMPANIES NATURAL GAS FORECASTING METHODOLOGY[67] AND SUGGEST THAT IT IS FLAWED AND MUST BE REJECTED. PLEASE RESPOND.

A. Simply put, CCEBA Witness Lucas fully understands as a witness for the solar industry that convincing the Commission to ignore the actual nearer-term market price of natural gas and instead direct the Companies to rely on higher economic forecasts in their IRPs, the solar development community would be poised for significant monetary gain as his arguments would be carried forward to the upcoming avoided cost proceedings in North Carolina and South Carolina. Unfortunately, he spends a great deal of time advancing several flawed arguments that are not only inaccurate, but also have been rejected in other proceedings as I previously mentioned. While I will address a few of his flawed arguments below, it is important for the Commission to understand that the historic use of fundamental price forecasts as suggested be Witness Lucas has resulted in significant "over-payment risk" and excess costs to customers both historically and on a prospective basis.

[67] CCEBA Lucas Direct, at 3, 62-103.

Q. CAN YOU EXPLAIN WHAT YOU MEAN BY OVER-PAYMENT RISK AND EXCESS COSTS TO CUSTOMERS.

A. Yes. This was a significant issue in the 2019 Avoided Cost Dockets.[68] Under PURPA, the Companies are obligated to enter into long-term fixed-price PPAs with QFs. Over-payment risk arises because the market price for power (which is driven by the price of the marginal resource, often natural gas) changes over the term of the QF contract, and FERC has held that neither the utility nor the Commission may modify the QF's contract if changes in the Companies' avoided costs occur in the future. This effectively means that the Companies' customers are locked into paying for the QF's power at stale avoided cost rates for the full term of the PPA, regardless of whether market conditions change or whether the value of the QF energy and capacity decreases. This "over-payment risk" has been a significant consideration in the Companies' service territories in the Carolinas as there has been a proliferation of solar QF generation seeking to lock in long-term fixed price PURPA agreements.

Based on recent analysis, the realized overpayments for 2020 alone of approximately $170 million in excess of the actual value the solar provided customers. The Commission also recently recognized and relied upon the Companies' testimony in the 2019 Avoided Cost Dockets demonstrating that future

[68] *See* Order No. 2019-881(A), at 36-37, 42 Docket Nos. 2019-185-E and 2019-186-E (Jan. 2, 2020) (Summarizing DEP/DEC Witness Brown's testimony on over-payment risk and concluding that "the Commission finds merit in the argument that the Commission should carefully consider the overpayment risk of administratively forecasting avoided cost rates under longer term PURPA contracts that are increasingly uncertain and subject to future changes in the utilities' avoided costs. The Commission also finds persuasive Duke Witness Brown's testimony describing Duke's recent experience with PURPA implementation in North Carolina[.]").

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solar QF over-payment obligations were projected to be over 2 billion dollars at that time.[69] While more than a year has passed since the 2019 proceeding, I would expect the total financial obligation and calculation of customer losses would be the same or greater if it was calculated today given recent continuing decline in natural gas market conditions.

Q. DO YOU AGREE WITH MR. LUCAS'S STATEMENT THAT NATURAL GAS PRICES ARE "BEST CONSIDERED AS HIGHLY VOLATILE?" PLEASE EXPLAIN WHY.

A. No. Highly volatile is a very subjective term. Witness Lucas presents several selective graphs and charts on natural gas future prices, but he does not mention larger problems with using fundamental price forecasts when a liquid transactable market is available. Simply put fundamental forecasts can vary significantly over time and can vary from one forecast provider to the next. So while there are multiple fundamental price forecasts at any point in time there is only a single forward market price at any point in time. Consider my Figure 6 below that very simply illustrates three central points:

1) Fundamental price forecasts have consistently overstated the market over the last several years;
2) Fundamental price forecasts can move significantly from one year to the next displaying greater year-to-year variance than the actual forward market; and
3) Fundamental price forecasts differ from one forecast to the next while there is a single market price.

[69] *See id.* at 36, 154 (identifying Companies' testimony that "Companies' recent experience has been that paying above-market avoided cost prices over a long period of time for an unprecedented number of QF contracts resulted in the current $2.26 billion overpayment obligation based upon DEC's and DEP's existing PURPA obligations" and determining that "such risks are an important consideration in reducing the risk on the using and consuming public[.]").

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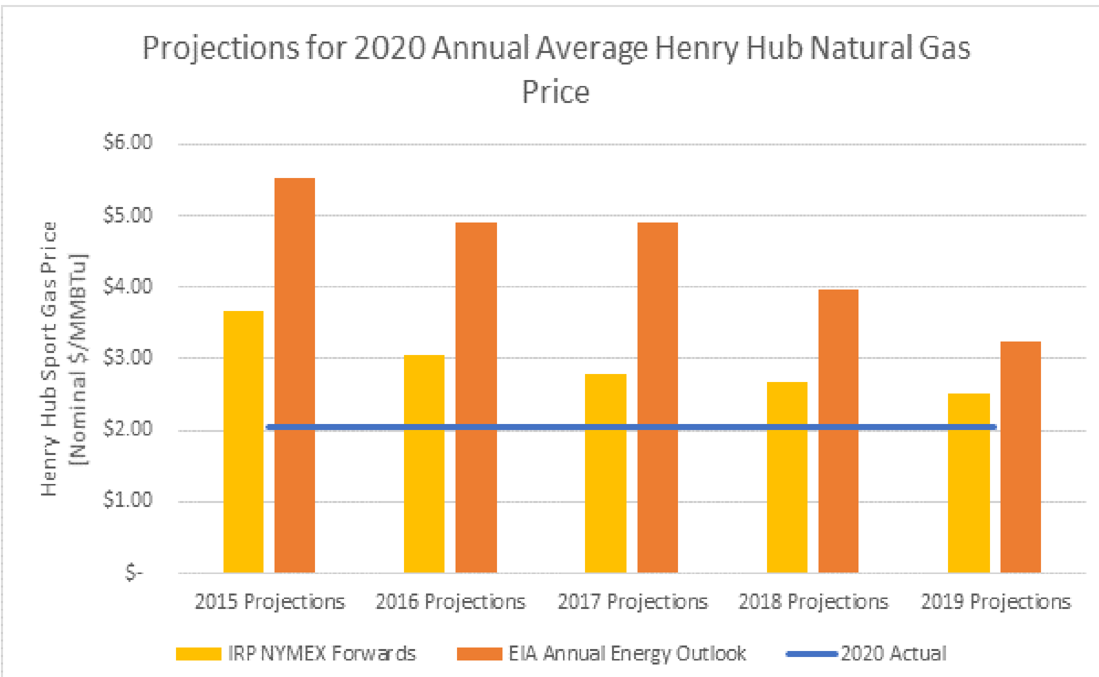
Figure 6 below shows the historic views for annual average 2020 Henry Hub prices for the five years leading up to 2020. The yellow bars in the graph below represent the 2020 NYMEX Forward market prices used in the 2015, 2016 and 2017, 2018 and 2019 IRPs. The orange bars are the 2020 annual average projections from the EIA's Annual Energy Outlook from 2015, 2016, 2017, 2018 and 2019. The blue line reflects the actual 2020 Henry Hub annual average spot prices as published by the EIA.

Snider Rebuttal Figure 6: Benchmarking 2020 Average Henry Hub Natural Gas Price to Prior Years Forecasts



As discussed above, and as seen in the Figure, the NYMEX Forward projections were more consistent with the actual 2020 price as compared to the price projected for 2020 in the fundamental forecasts. IHS was not the Companies' fundamental gas forecast provided in 2015 and 2016 so they were omitted from Rebuttal Figure 6.

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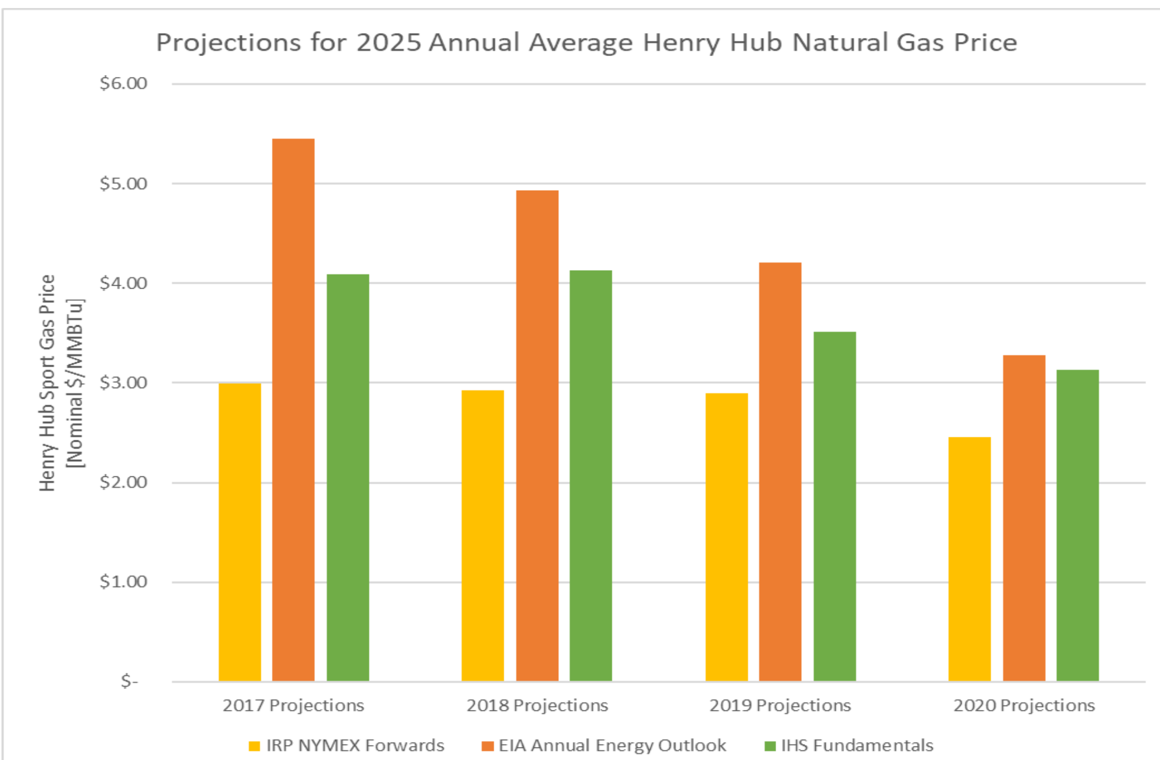
Taking these same forecasts and adding in the company's current fundamental gas price provider, IHS, we can see a similar trend evolving for 2025. NYMEX Market prices are more stable on a year-to-year basis as the long-term fundamental forecasts continue to come down over time recognizing the longer-term stability in the market. While we don't know what the price in 2025 will be, we can see that over time, from the Figure 6 and Figure 7, in the near and midterm, the fundamental forecasts have recognized the market and adjust their forecasts accordingly. Finally, my figure also shows the discrepancy between fundamental forecasts relative to a single market view.

Snider Rebuttal Figure 7: Projections for 2025 Annual Average Henry Hub Natural Gas Price



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Q. WITNESS LUCAS ALSO CHALLENGES THE COMPANIES' RELIANCE ON 10 YEARS OF MARKET PRICING CLAIMING LACK OF LIQUIDITY OVER THAT DURATION. DO YOU AGREE WITH HIS ASSESSMENT?

A. No. Witness Lucas arrives at his liquidity arguments by simply looking at the short-term nature of the NYMEX futures market and then assuming there is limited availability to transact significant volumes in the longer term Over-The-Counter ("OTC") swap market. These assumptions are simply incorrect. He goes on to challenge the robustness of the OTC forward market and the prices that result from those swaps. Witness Lucas is mistaken in his contention that transactable market prices over the ten-year period are not robust. Simply put, the robustness of a market can be demonstrated by the fact that there are multiple brokers that will transact natural gas swaps over this period. In addition, when seeking quotes for OTC swaps, market participants have narrow price differentials between quoted bid prices and offer prices which is another indication of the liquidity and robustness of the market.

Q. WITNESS LUCAS ALSO TAKES ISSUES WITH THE RELATIVELY SMALL VOLUMES OF 10 YEAR PURCHASES THE COMPANIES UNDERTAKE AS A REASON FOR REJECTING THE USE OF MARKET PRICES. PLEASE EXPLAIN THE FLAWS IN THIS ARGUMENT?

A. Mr. Lucas suggests that it would be "instructive to 6 see the price to purchase 50% of Duke's projected natural gas consumption from for the next ten years on a fixed

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price contract" to demonstrate the robustness of the forward OTC market.[70] Mr. Lucas lacks fundamental perspective and understanding of how fuel hedging works in the industry and the purpose of hedging programs. The Company's small transaction volumes are a function of intentional good business practices rather than an indication of reduced market liquidity. The Companies, in fact, receive quotes from multiple brokers for volumes substantially larger than what actually ends up being transacted.

As is often discussed in the context of fuel cost recovery, I will try to briefly summarize the general purposes of utility natural gas hedging. First, fuel hedging does not attempt to pick prices at given points in time; instead, the intent of a hedge program is to reduce annual volatility in fuel related costs consumers see in their bills. This is accomplished through systematic purchases across time and not large purchases at one point in time. Second, the further out in time fuel is being hedged, the smaller the volumes that are hedged since additional hedge volumes will be added across time and volumetric demand uncertainty will decline. Third, any hedge has the potential to go up or down in value so concentrated large volume purchases at a single point in time can introduce unacceptable risk for consumers.

Furthermore, Mr. Lucas either lacks the historic perspective, or is choosing to omit the historic perspective, regarding the actual rationale for the Companies' periodic purchasing of ten-year natural gas OTC swaps. This purpose, which has been extensively vetted in prior NCUC avoided cost dockets I mentioned earlier in

[70] CCEBA Lucas Direct, at 74.

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my testimony, was to ensure fair indifference prices were being established under the PURPA avoided cost construct. This was done in order to minimize the risk of further exacerbating the dramatic overpayments to solar QFs that customers are currently experiencing. As a result, the volumes of ten-year natural gas purchases were and continue to be, intentionally relatively small in nature. Beyond price equivalence, this volumetric discipline also avoids repeating the same volumetric risk that has manifested as a result of unchecked volumes of solar QFs putting power onto the system at given points in time. While the Companies may be somewhat unique in their purchasing of ten-year forward natural gas swaps, this practice was driven by the equally unique nature of solar QF over-payments not seen elsewhere in the industry.

Finally, I would also point out that the Companies are simply one market participant in the natural gas industry, and it is not reasonable to assume that simply because the Companies do not buy large volumes that the market itself is not robust. As I stated earlier, the Companies receive quotes from multiple sources for volumes much greater than the actual purchases that are being made which is an indication of robust market liquidity contrary to the Witness Lucas's representation of the OTC market.

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Q. IN YOUR EXPERIENCE WITH FINANCIAL MARKETS AND ACCOUNTING RULES WOULD IT BE AN ACCEPTABLE PRACTICE TO VALUE A FORWARD PURCHASE OR SALE BASED ON A FUNDAMENTAL FORECAST WHEN ACTUAL MARKET PRICES WERE AVAILABLE?

A. No, it would not. While I am not an accountant, I have had substantial experience in the valuation of forward power and gas positions. I have worked closely with accountants and auditors in the past to ensure positions that are entered into at one point in time are fairly valued against the prevailing market at another point in time for reporting purposes when financial statements are prepared. The Financial Accounting Standards Board (FASB) establishes what are known as mark-to-market rules that requires valuations to be based on actual market prices rather than a Company selected fundamental forecast. Additionally, sound risk management principles and regulations require stressing those positions based on market prices and implied market volatility parameters rather than reliance on fundamental price forecasts.

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Q. HAVE THERE BEEN RECENT LEGISLATIVE CHANGES AT THE STATE OR FEDERAL LEVEL THAT HAVE BEEN MADE AT LEAST IN PART TO ADDRESS THE RISK ASSOCIATED WITH SETTING PURCHASE OBLIGATIONS ON LONGER-TERM FUNDAMENTAL OR ADMINISTRATIVELY-SET PRICES RATHER THAN ACTUAL MARKET PRICES?

A. Yes. I would contend that both North Carolina's 2017 Competitive Energy Solutions legislation, ("NC HB 589") and South Carolina's 2019 Act 62 attempt to mitigate this risk. NC HB 589 limits fixed price QF contracts over 1 MW in size to a five-year term to avoid overpayment risk while SC Act 62 limits prices for QF purchase contracts 10 years or longer to the Commission approved-10 year avoided cost price even if the contract is longer than 10 years. The South Carolina legislature was clearly concerned with consumer overpayment risk resulting from reliance on non-market based price forecasts when it put this consumer protection into the Act. I would expect Witness Lucas is aware of this fact and would prefer to see the Commission to mandate the use of lagging fundamental gas prices today to the extent they are currently above the prevailing market price, which would result in a higher ten-year avoided cost rate. In the converse, if the 10-year fundamental forecast for gas prices were lower than the prevailing market prices, I would expect the witness to take the opposite side of his current argument. Finally, also in 2019, FERC Order 872 amended the federal PURPA implementation rules in a manner that now affords states the ability, at their discretion, to set PURPA rates that do not include a long-term fixed energy component siting concerns of overpayment risk for consumers. These policies precisely align with the Companies' consistent and repeated use of 10 years of forward market fuel prices for both IRP and avoided cost purposes in South Carolina.

Q. CAN YOU BRIEFLY SUMMARIZE YOUR OBJECTIONS TO WITNESS LUCAS'S RECOMMENDATION TO MOVE AWAY FROM ACTUAL MARKET PRICES IN FAVOR OF EIA OR IHS FUNDAMENTAL PRICE FORECASTS?

A. First, use of fundamental market prices that are in excess of actual market prices is flawed and would result in significant customer overpayments if the same logic was followed in the upcoming avoided cost docket.

Second, the use of fundamental prices over market prices is an issue that has been widely debated in prior dockets and similar arguments to Mr. Lucas's have been resoundingly rejected.

Third, while the IRP is not subject to the rules of the FASB, the use of price forecasts over market prices is directionally inconsistent with accepted accounting and risk management rules and regulations.

Finally, the recommendation itself contradicts the intent and direction of recent state and federal legislation put in place to protect consumers against the very risks that would ensue if this recommendation were to be adopted.

(D) <u>The 2020 IRPs Meet Act 62's Requirements to Reasonably Evaluate Existing System Resources and to Plan for Resource Retirements in the Future</u>

Q. PLEASE REINTRODUCE THE ACT 62 REQUIREMENTS TO ADDRESS THE COMPANIES' EXISTING SYSTEM RESOURCES, AS PART OF THEIR IRPS.

A. Act 62 requires utilities to provide "data regarding the utility's current generation portfolio, including the age, licensing status, and remaining estimated life of operation for each facility in the portfolio."[71] In addition, Act 62's directive to propose plans for meeting current and future capacity needs must necessarily involve an assessment of the utility's existing resource capacity.[72]

Q. DOES ORS SUPPORT THE COMPANIES' ANALYSIS OF EXISTING SYSTEM RESOURCES, AS PRESENTED IN THE 2020 IRPS?

A. Generally, yes**.** The requirement to describe existing system resources does not involve strategic operational decisions by the Companies; rather, the task is to transparently describe existing system capabilities and project the longevity of operating such resources into the future. Act 62 also directs the Commission to assess the Companies' "diversity of generation supply."[73] ORS noted that the Companies have "a diverse fleet of generating units consisting of nuclear, coal CCGT, CT, hydroelectric, solar, and battery energy storage resources."[74]

[71] S.C. Code Ann. § 58-37-40(B)(1)(f).
[72] *Id.* at §§ 58-37-40(B)(1)(e) & (g).
[73] S.C. Code Ann. § 58-37-40(C)(2)(f).
[74] See ORS Report (DEC), at 59; ORS Report (DEP), at 59.

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Q. DOES ORS PRESENT ANY RECOMMENDED IMPROVEMENTS TO BE ADDRESSED IN FUTURE IRPS?

A. Yes. ORS presents a number of recommendations regarding the Companies' analysis of existing system resources to be addressed in a modified or in future IRPs, including recommendations for presenting data in PROSYM—an hourly production cost model used to simulate the operations of the generation fleet to meet demand in every hour of study horizon—as well as addressing nuclear relicensing, hydro relicensing, and coal retirements.

1. The Companies Provide Additional Detail on PROSYM Data Inputs as Recommended by ORS

Q. WHAT IMPROVEMENTS DOES ORS RECOMMEND REGARDING THE PRESENTATION OF PROSYM DATA?

A. ORS experienced some difficulty reconciling PROSYM data with information from other sources, including the Companies' Load, Capacity, and Reserves Table (the "LCR Table"), which it perceived to be due to inconsistencies in the data between these two sources. Accordingly, ORS recommends the Companies create a cross reference table comparing each resource modeled in PROSYM (e.g., generating units, demand response, purchase contracts, EE, etc.) to the corresponding data in the LCR Table for the base case with carbon policy and the base case without carbon policy.

Q. DO THE COMPANIES AGREE WITH ORS'S RECOMMENDATION?

A. The Companies do not believe there is any discrepancy in the data inputs used in PROSYM and the LCR Table. While the Companies want to enhance transparency

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and avoid confusion, they do not believe that a cross reference table in the IRP is a feasible way to meet that goal.

Q. PLEASE EXPLAIN.

A. PROSYM is a complex production cost modeling application that includes numerous and voluminous input variables. The LCR Table is a more simplified version of the inputs and assumptions utilized in the IRP. Both are important tools in the development and presentation of the IRP analyses. Both tools utilize the same inputs, expansion plan and result in the same reserve margins. The Companies review inputs and data set up for these tools over the course of several weeks during the IRP process to insure consistency of inputs and calculation of reserve margins. The difficulty in reducing the comparison of these inputs for these tools to a cross-reference table is that many inputs in PROSYM are input in different forms or in different ways (hourly/monthly inputs vs. annual inputs; load profiles vs. discrete variables, conditional requirements of certain data in PROSYM vs. simplifying assumptions, etc.) as compared to the LCR Table. The sheer amount of inputs on an annual basis alone precludes a comparable "table" from being formatted in a useable way for filing with the Commission. We believe reducing this information to a printed table may also invites more confusion with data comparison rather than clarifying it.

Q. DO THE COMPANIES PROPOSE ANY ALTERNATIVE SOLUTION TO ASSIST ORS WITH THE COMPARISON OF DATA INPUTS BETWEEN PROSYM AND THE LCR TABLE FOR THE BASE CASE WITH CARBON AND BASE CASE WITHOUT CARBON?

A. First, the Companies will not utilize PROSYM as its production cost model in future IRPs, but rather will transition to the Encompass modeling software platform, licensed from Anchor Power Solutions, LLC ("Encompass"). Even so, the Companies believe the best format for supplying this comparison information is in a comparison worksheet, such as the information presented in Snider Rebuttal Exhibit 6. Information has been provided to direct the specific data item from PROSYM to the data source in the LCR Table. Additionally, notes have been provided as to why the information may not match between the two sources because of input differences. While this information has been provided in this Exhibit, the printed format that would need to be included in an official filing document as a cross-reference table is not useful, as the information is too voluminous. Providing the information to intervenors in an Excel worksheet through discovery is the preferred and more reasonable method.

The Companies will prepare this comparison worksheet for the Base Cases in future IRPs as a standard discovery response included with the "Model Inputs" Excel files provided to ORS and other intervenors in discovery each year. The Companies also appreciate ORS's further explanation of their concerns in discovery.[75] In the future, the Companies recommend that if confusion regarding

[75] ORS Response to DEC/DEP First Set of Interrogatories 1-2.

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the production cost model inputs and the LCR Table still exists after the comparison worksheet is received and reviewed, that the ORS request a telephone discussion with the Companies' resource planning personnel to provide clarification and to resolve any ambiguity.

2. <u>The Companies Provide Additional Detail on Nuclear Relicensing Plans, as Recommended by ORS</u>

Q. PLEASE DESCRIBE THE ORS'S RECOMMENDATION REGARDING THE COMPANIES' EFFORTS TO RELICENSE ITS NUCLEAR PLANTS.

A. ORS recommends the Companies supply additional information regarding their nuclear relicensing plans in a modified IRP in this proceeding. In particular, ORS seeks information regarding DEC's plans to pursue relicensing of the Oconee nuclear units, as well as an explanation as to why it is beginning the relicensing process for those units well in advance of their expiration.

Q. DO THE COMPANIES AGREE WITH ORS'S RECOMMENDATION?

A. Yes. The Companies are providing the requested information as Snider Rebuttal Exhibit 7, which is attached to my testimony.

3. <u>The Companies Provide Additional Detail on Hydro Relicensing Plans, as Recommended by ORS</u>

Q. PLEASE DESCRIBE THE ORS'S RECOMMENDATION REGARDING THE COMPANIES' EFFORTS TO RELICENSE ITS HYDRO FACILITIES?

A. ORS recommends that DEC provide details on the relicensing status of its Bad Creek Pumped Hydro Units, which are set to expire in 2027. In particular, ORS recommends that DEC provide the status of its plans to relicense the units,

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including any actions it will have to take as part of the relicensing process and any related costs it will incur.

Q. DO THE COMPANIES AGREE WITH ORS'S RECOMMENDATION?

A. Yes. The Companies are providing the requested information as Snider Rebuttal Exhibit 8, which is attached to my testimony.

4. <u>The Companies Provide Extensive Additional Detail on the 2020 IRPs' Coal Retirements Analysis and Plan to Discus with ORS Prior to Filing Next Comprehensive IRPs in 2022</u>

Q. DOES ACT 62 REQUIRE THE COMPANIES TO ADDRESS FACILITY RETIREMENT ASSUMPTIONS AS PART OF THEIR IRPs?

A. Yes. Act 62 requires electrical utilities to address facility retirement assumptions as part of their IRPs.[76]

Q. DOES THE ORS COMMENT ON THE COMPANIES FACILITY RETIREMENT ASSUMPTIONS?

A. Yes. ORS recognizes that the Companies' performed a detailed three step analysis but questioned whether the retirement date(s) established by the Companies' 2020 IRPs represent the "optimal date for retirement . . . since the Company did not perform an optimization analysis to compare the retirement resources to optimal replacements."[77]

Q. DOES THE ORS MAKE A RECOMMENDATION WITH RESPECT TO THE COMPANIES' COAL RETIREMENT ANALYSIS?

A. Yes. ORS recommends the Companies provide evidence that the optimal

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[76] S.C. Code Ann. 58-37-40(B)(1)(e)(ii).
[77] *See* ORS Report (DEC), at 65; ORS Report (DEP), at 20.

retirement dates that were determined with the Sequential Peaker Method are comparable to the optimal retirement dates the System Optimizer model would produce if it were used in the retirement study.

Q. HOW DO THE COMPANIES SUGGEST PROCEEDING WITH THE ORS RECOMMENDATION TO BENCHMARK ITS RETIREMENT ANALYSIS WITH A CAPACITY EXPANSION MODEL?

A. I will explain below how the Companies' retirement analysis approach more accurately captures the economic retirement dates of the coal units. However, given the complexity and rigorous analysis required to analyze coal retirements, the Company proposes to engage with ORS and their technical consultants to discuss potential enhancement techniques for evaluating coal retirements for future comprehensive IRPs. Since the Company is switching to the Encompass model as discussed in the stakeholder process, we will also continue to evaluate the capabilities and enhancements our new modeling software will provide with respect to co-optimizing retirements of the Companies' coal fleet. To the extent the new Encompass software is capable of fully optimizing retirement dates and replacement options, the Company will agree to perform that analysis in the comprehensive IRP filing in 2022. In view of upcoming new modeling capabilities, the System Optimizer model's lack of ability to fully optimize batteries, the fact that no pending actions are dependent on this analysis and taking into consideration this issue will be revisited in next year's comprehensive IRP, we recommend not incurring the administrative expense and complexity of benchmarking the current approach with a System Optimizer only approach.

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As I discuss in other parts of my testimony, the Companies recognize that, in order to transition the generation fleet while continuing to provide, safe, reliable and affordable energy to customers, it has the immense task ahead to retire and reliably replace these resources at the appropriate pace. Engagement with stakeholders, including ORS as well as the NC Public Staff, will continue to inform and refine this process.

Q. DO YOU AGREE WITH THIS ORS'S ASSESSMENT TO BENCHMARK THE COMPANIES' RETIREMENT ANALYSIS IN A CAPACITY EXPANSION MODEL?

A. No. While the Companies appreciate the conceptual idea of using the capacity expansion model to perform all resource optimization in a single computational process, this approach was not practical in this case due limitations of the capacity expansion model, the complexity of analysis, and the magnitude of the coal retirements being contemplated as I will explain.

Q. PRIOR TO ADDRESSING TECHNICAL ISSUES AND COMPLEXITIES PLEASE PROVIDE AN OVERVIEW OF THE COMPONENTS OF A RETIREMENT ANALYSIS AND A SUMMARY OF THE ISSUE?

A. I will go into much more detail below, but retirement analysis examines the potential retirement of a generator, or in this case a set of generators (the Companies' coal generation) and attempts to answer two questions: When is the appropriate time to retire each plant being studied and once retired what is the appropriate resource to replace the retired coal plant or the "When" and the "What"? The complexities arise because there are essentially two different types of system modeling tools in resource planning that can and are used in the determination of the when and the what. One is an "capacity expansion model" generally used for screening resource alternatives to meet future needs and the other is a detailed "production cost model" used to examine detailed system operations and cost data hour by hour for all years in the planning horizon. The general issue at hand is there are differing ways to apply these tools to perform the retirement analysis in order to best answer the "when" to retire as well as the "what" to replace it with? Given the complexities of the retirement analysis in this case there is question as to the best utilization of these models. The Companies used the more detailed production cost model in an iterative manner to identify the when to retire question while using both models to identify the best "what" to replace it with.

Q. WAS THE COMPANIES' 2020 IRP COAL RETIREMENT ANALYSIS MORE COMPLEX THAN THE TYPICAL USE OF CAPACITY EXPANSION MODELS?

A. Yes. The complexity arose, in part, because the Companies were acting under direction from the NCUC to perform a comprehensive coal retirement analyses for all coal units in the 2020 IRPs.[78] The NCUC directives included a requirement to perform analyses to determine earliest practicable retirement dates "not constrained by least cost planning principles," as well as economic retirement dates (using least cost planning principles) with consideration of practical factors such as "transmission and distribution infrastructure investments that will be required to

[78] *See Order Accepting Filing of 2019 Update Reports and Accepting 2019 REPS Compliance Plans*, N.C.U.C. Docket No. E-100 Sub 157 (April 6, 2020) ("2019 NCUC IRP Order").

make a successful transition."[79] This required consideration of transmission and distribution implications of retirements and replacement generation in both scenarios. While the Earliest Practicable Coal Retirement analysis sets aside normal least cost planning principles to determine the earliest date at which the coal units could be retired, this NCUC-mandated study objective is not compatible with model optimization. Additionally, the scale of the transition, the complexity of accurately quantifying the on-going costs of the coal units, and the incorporation of transmission and distribution impacts in the economic retirement analysis necessitated a more detailed analysis as discussed below.

Q. ONE COMPONENT OF THE COMPANIES' RETIREMENT ANALYSIS IS CALLED THE SEQUENTIAL PEAKER METHOD. PLEASE REINTRODUCE THIS RETIREMENT ANALYSIS METHODOLOGY.

A. The Sequential Peaker Method is a retirement methodology used specifically to evaluate the appropriate coal retirements dates for the 2020 DEC and DEP IRPs. The Companies have a unique challenge in transitioning the over 10,000 MW of coal capacity in the Carolinas to equally reliable capacity and energy production. The major benefits of using the Sequential Peaker Method include the following:

- Detailed Hourly System Production Cost – The Sequential Peaker Method allows the Companies to use an hourly detailed and chronological production cost model to more accurately project the operations of these coal plants and the overall cost of the system. This step used PROSYM, a detailed production cost model that looks at each

[79] 2019 NCUC IRP Order, at 9.

hour in the planning horizon as opposed to the capacity expansion model, System Optimizer, which uses a simplified subset of representative hours throughout the year. The simplified computations do not address operating reserve requirements, unit flexibility and limitations such as changing heat rates throughout the operating range, ramp rates, minimum load restrictions, outages, must run requirements and the unit's ability to use multiple fuels.

- On-Going Capital and Fixed O&M Cost Impact – The Capacity Expansion Model uses a forward-looking approach that cannot reflect the reduction of unit capital and O&M cost prior to retirement. The Companies have a dynamic capital and O&M cost projection model that estimates the on-going capital based on the expected unit operation and the reality that as a unit approaches retirement capital and O&M investments are minimized. The Sequential Peaker Method in which every year is evaluated independently can include the cost reductions prior to retirement while the use of a Capacity Expansion Model cannot.
- Transparency – The Sequential Peaker Method allows station-by-station evaluation on a year-by-year basis to accurately project the most economic retirement date for each of these stations. The Sequential Peaker Method uses an iterative approach, evaluating a coal unit or group of units one at time, to quantify the value of the coal units to the overall system, recognizing that the value of a unit to the system is dependent on the retirements that occur before it. Capacity expansion

models are sometimes viewed as a "black box" that produce results without clarity as to how the decision was made. The Sequential Peaker Method offers clarity and repeatable calculations.

Q. WAS THE SEQUENTIAL PEAKER METHOD DESIGNED AND USED TO ACHIEVE A SPECIFIED ANALYTICAL OBJECTIVE?

A. Yes. The Sequential Peaker Method was used only to identify the economic retirement dates of the coal units and does not imply a natural gas peaker will replace the retiring unit. This is an important point since the retirement dates determined in the Sequential Peaker Method were then input into the capacity expansion model referenced by the ORS to assist in the selection of the appropriate replacement resource as used in the development of the Base Case Portfolios.

Q. YOU MENTIONED THE TRANSITION OF 10,000 MW OF COAL CAPACITY. IS THAT A RELATIVELY HIGH NUMBER THROUGHOUT THE INDUSTRY?

A. Yes. Analyzing and optimizing the retirement of this magnitude of units to safely, reliably, and affordably replace this number of plants while the rest of the resource mix is also changing presents unique challenges. In fact, I am not aware of any other utility in the nation that has attempted to use a capacity expansion model to simultaneously attempt to co-optimize both the date of retirement and replacement resources given retirements of this magnitude and the model limitations I have discussed.

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Q. THE ORS RECOMMENDS THAT THE COMPANIES RUN THE CAPACITY EXPANSION MODEL, SYSTEM OPTIMIZER TO ANALYZE THE PROJECTED RETIREMENTS OF THE COAL UNITS WHILE CO-OPTIMIZING THE SYSTEM. PLEASE EXPLAIN THE ISSUES WITH THIS APPROACH.

A. Used in isolation, System Optimizer was determined not to be the most robust method for co-optimizing retirement dates and replacement resource selections for coal retirements in the DEC and DEP systems given the issues I previously discussed. System Optimizer is a capacity screening model; it does not have the flexibility to accurately capture changing cost assumptions. Additionally, the simplifying hourly analysis that System Optimizer uses with the representative hours approach, as discussed later in my testimony, is not designed to capture inter-hour variation yielding less accurate system operations projections.

Q. PLEASE EXPLAIN HOW CAPACITY EXPANSION MODELS ARE USED IN RESOURCE PLANNING.

A. As mentioned above, System Optimizer is a capacity screening tool**.** The model can be used to help identify cost-effective system resources, but in best practices of resource planning, screening in a capacity expansion model will be followed with analysis from detailed production cost model runs to refine and verify screening results. While capacity expansion models are helpful in quickly assessing a broad range of potential portfolios, the Companies rely on their production cost modeling to verify the results.

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Q. PLEASE EXPLAIN HOW CAPACITY EXPANSION MODELS SIMPLIFY ANALYSES TO DETERMINE LEAST COST RESOURCE PORTFOLIO COMPOSITIONS.

A. Capacity expansion models such as System Optimizer run thousands of simulations over long time horizons, typically 20 or more years. To remain practical in computer memory requirements and execution speed, time is represented in buckets larger than individual hours. System Optimizer uses this "representative hours" approach, in which average load values in each representative time bucket are compared to these thousands of portfolio simulations.

This model approach does not consider chronology, but rather multiplies each of these representative hour time buckets of load and generation by the number of those hours in each month, to simulate the system's operation of an entire month. This is repeated for every month over the planning horizon and complied together to create a net present value for each portfolio. The model uses this simplifying approach to run iterations of thousands of portfolios to determine which mix of resources minimizes the present value revenue requirement of the system over planning horizon.

Q. IS THIS COMPUTATIONAL SIMPLIFICATION THE BEST METHODOLOGY FOR ANALYZING THE ECONOMICS OF THE COMPANIES' COAL FLEETS?

A. No. Analyzing the capacity additions with a growing system the size of DEC and DEP can be challenging enough to get accurate and reliable results. The analysis is further complicated if the model also must select the economic retirement dates of nearly 10,000 MW, rather than relying on the retirements as an input and capacity additions are optimized around it. Finally, the lack of hourly detail I described for capacity expansion models limit their ability to accurately value energy storage, which is better valued in a detailed production cost model.

Q. HOW DOES THE COMPANIES' DYNAMIC COST MODELING IMPROVE THE COAL RETIREMENT EVALUATION?

A. The on-going capital and fixed operations and maintenance costs of the coal units is a critically important component of determining the economic retirement dates. The dynamic cost model for coal units is a significant improvement over retirement analysis in a capacity expansion model.

While changes in production cost are captured in this analysis, much of the economic evaluation depends on the capital and fixed operations and maintenance costs of the coal units compared to the same costs for new capacity, as discussed above and in detail in the 2020 IRPs[80] The dynamic cost model uses assumptions that will appropriately lower maintenance costs, if the unit is expected to retire in the near term. In practice today, as a unit's projected retirement date nears, the Companies will continue to invest less and less in the unit, investing just enough to get the unit to its retirement date. The dynamic cost model for the existing coal units captures this "wind down" in investment costs. This approach is a better approximation of actual costs being invested in and maintaining these units. Compared to a capacity expansion model, this provides significant benefit as those models are only able to evaluate a single unchanging stream of costs into the future

[80] See DEC 2020 IRP, at 80; DEP 2020 IRP, at 83.

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which may prematurely retire a unit, believing it can reduce the cost of the system by avoiding costs that are not reflective of potential "wind down" investment strategies.

Additionally, the dynamic cost model more accurately projects future investments and costs in the coal unit by using projected service hours, generation levels, and carbon emissions to identify if different operation levels or modes of operation can reduce costs. Many maintenance cycles are service hours based. To the extent that maintenance may be able to be deferred, reduced or eliminated, while maintaining unit reliability, the model can reduce costs to reflect these parameters. To get an accurate forecast of these costs, a granular, hourly production cost model, which maintains the chronology of the hours in a year to accurately reflect how much the unit might run is required.

As discussed above, many capacity expansion models, such as System Optimizer, average similar hours together into time buckets to more quickly evaluate portfolio options and how a system would dispatch against that representative hour. In this process, the operation of a unit may be overstated or understated because the model does not see the explicit higher or lower loads from hour to hour, and how the unit would operate in the transition from one time bucket to another. When an hourly production cost model is used, a unit's flexibilities and cost savings between different time periods are appropriately reflected in the model and carried over into the dynamic cost modeling tool to appropriately reflect the cost of maintaining the units. This process yields a more reliable and trustworthy representation of how the unit is expected to operate and as such, how much investment will be made to the unit, to more accurately determine the economical retirement of the units.

Q. ARE THERE OTHER REASONS WHY THE SEQUENTIAL PEAKER METHOD WAS THE PREFERRED OPTION FOR THE ECONOMIC COAL RETIREMENT ANALYSIS?

A. Yes. The step-by-step evaluation process and dynamic cost modeling will also capture cost shifting. If a unit is retired and consequently another unit is forced to run more to meet energy needs, the differences in those operation profiles in the two scenarios are captured in the Sequential Peaker Method. Appropriately shifting costs from one unit to another, if it is called on to operate more because another unit has retired ahead of it in the capacity expansion model, is more difficult to capture as these models use static on-going costs streams as previously discussed. The step-by-step unit evaluation also provides transparency. With the sequential peaker method, the Companies can isolate that a unit was retired in a particular year because the accurately modeled costs to maintain and operate a unit were more costly to the system than the replacement capacity.

Q. INTERVENORS, INCLUDING THE ORS AND OTHER ADVOCACY GROUPS, HAVE MADE THE ARGUMENT THAT USING OTHER RESOURCES AS THE REPLACEMENT FOR COAL UNITS MAY PROVIDE ADDITIONAL ECONOMIC BENEFIT AND ALLOW COAL UNITS TO RETIRE EARLIER. HOW DO YOU RESPOND?

A. While this may be true in theory, it is somewhat unlikely. First, the concern only applies to non-peaker replacement generation in the IRP since the Sequential

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Peaker Method, by definition, picks the appropriate retirement date when an actual peaker was determined to be economic compared to the retiring coal unit. When the optimization step chose the limited amounts of storage and some combined cycles rather than a peaker, the question of further retirement acceleration really boils down to, given the higher capital costs of CCs and BESSs, is there enough production cost benefits from those resources to overcome the higher capital costs of those units and still warrant acceleration.

Q. PLEASE SUMMARIZE THE COMPANIES' POSITION ON THIS COMPLEX ISSUE.

A. The Companies appreciate the interest and intent of ORS's recommendation, and have provided this detailed explanation of the rationale for utilizing the Sequential Peaker Method. As I committed above, the Companies plan to engage with ORS as well as the NC Public Staff to continue to inform and refine their coal unit retirement analysis between now and the Companies' next comprehensive IRPs to be filed in 2022.

(E) <u>The Companies Present Generic Resource Options That are Based on Reasonable Assumptions in Compliance with Act 62</u>

Q. PLEASE REINTRODUCE ACT 62'S REQUIREMENTS FOR ADDRESSING NEW GENERATION TECHNOLOGIES, AS PART OF THEIR IRPs.

A. Act 62 requires the Companies to provide generation technology information for new generic resources contained in the IRP, including by providing the proposed capacity of the generation facility and fuel cost sensitivities under various reasonable scenarios.[81]

Q. DOES ORS SUPPORT THE COMPANIES' EVALUATION OF GENERIC GENERATING RESOURCE OPTIONS PRESENTED IN THE 2020 IRPS?

A. Yes. ORS concludes that the Companies' "assumptions generally appear to be reasonable for many of the generic resource type assumptions, when compared to the other sources of data."[82]

Q. DOES ORS PRESENT ANY RECOMMENDED IMPROVEMENTS TO BE ADDRESSED IN MODIFIED OR FUTURE IRPS?

A. Yes. ORS presents recommended improvements with respect to the Companies' combined heat and power ("CHP") assumptions, assessment of natural gas resources, battery energy storage system cost assumptions, assessment of solar PPAs as a resource option, and future evaluation of solar plus storage capacity values. I discuss each recommendation below.

1. Natural Gas Resources

a. 2020 IRP Combustion Turbine Cost Assumptions are Reasonable

Q. ORS RECOMMENDS DEC PROVIDE ADDITIONAL JUSTIFICATION FOR ITS COMBUSTION TURBINE ("CT") CAPITAL COST ASSUMPTION. PLEASE RESPOND.

A. DEC and DEP typically construct multiple CTs at a greenfield installation to realize economies of scale associated with land, roads, buildings and other common

[81] S.C. Code. Ann. § 58-37-40(B)(1)(b).
[82] ORS Sandonato Revised Exhibit AMS-1, at 72; Revised Exhibit AMS-2, at 72.

infrastructure. All DEC and DEP combustion turbines are located at multi-unit sites.[83] Consistent with this practice, the Companies' CT capital cost assumptions used in development of the Companies' 2020 IRPs are based on consultant estimates that reflect the average cost to construct four (4) F-Class CTs at a greenfield installation. The consultant provides estimates for the cost of the "first unit" and the "next unit" for a greenfield site. The first unit cost includes the infrastructure cost previously mentioned, and the first unit cost is significantly greater than the cost to construct the next unit at the site. The Companies' CT cost thus reflects the average cost to build one "first unit" and three "next units" based on the consultant estimates. The EIA data source is based on construction of a single unit at a greenfield site, and the NREL and NRC data sources included in Table 14 rely on the EIA data and thus also reflect the construction of a single unit at a greenfield site. The Lazard data also reflects the cost to build a single unit at a greenfield site although the source of the data is not known.

I would also highlight that the Companies' first unit cost, which reflects the cost to build the first CT at a greenfield site including infrastructure, is [BEGIN CONFIDENTIAL] [redacted]4 [END CONFIDENTIAL] The first unit estimate is approximately [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] greater than the $661/kW EIA estimate to build a single unit at a greenfield site, which provides a more appropriate comparison of data sources. In fact, the Companies' first unit cost is greater than or in-line with all of the Table 14 data sources except

[83] *See* 2020 DEC and DEP IRPs, Appendix B.
[84] *See* the Companies' Generic Unit Summary provided in response to ORS Request No. AIR 2-2(d).

for the NREL data which is not a valid comparison as discussed more fully in Confidential Snider Rebuttal Exhibit 9.

Q. IS THERE ANYTHING ELSE YOU WOULD LIKE TO ADD?

A. Yes. Both Companies have multiple brownfield sites with potential future use for baseload and peaking installations. The availability of these existing brownfield sites may further reduce the cost of future additions compared to the assumptions used in the IRP.

Q. DO YOU BELIEVE THAT THE CT CAPITAL COST USED IN DEVELOPMENT OF THE COMPANIES' IRPs IS REASONABLE?

A. Yes, the Companies' CT cost reflects the economies of scale associated with constructing multiple units at a single site consistent with DEC's and DEP's actual practice. I believe that the CT capital cost used in developing the Companies' 2020 IRPs provides a reasonable estimate for the cost of future peaking capacity and the use of a higher CT estimate would result in the non-optimal selection of resources in the IRP resulting in higher costs to consumers. Snider Rebuttal Exhibit 9 of my testimony provides greater detail of the CT cost comparison data sources

b. <u>Witness Fitch's Carbon Stranding and Climate Risk Report's Analysis Should be Rejected as Inaccurate and Mis-informed about the Cost and Role of Natural Gas as a bridge in the Companies' Net-Zero Carbon Future</u>

Q. BEFORE ADDRESSING INTERVENORS' ARGUMENTS ON THIS TOPIC, PLEASE REINTRODUCE THE ROLE OF NATURAL GAS IN THE COMPANIES' 2020 IRPs.

A. Overall, natural gas generation is a valuable resource for customers as one component of a broader transition plan that decarbonizes the Company's portfolio

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toward net-zero emissions by 2050. Natural gas generation resources keep prices low today and going forward while providing high levels of reliability for customers.

Natural gas-fired generation is a proven and cost-effective dispatchable technology that has a long history of reliably serving customers with the ability to provide baseload, intermediate, and peaking energy needs in a flexible manner. As discussed by Witness Roberts, the flexibility and reliability of the technology also aids system operators in ensuring a reliable system by providing the ramping and dispatchability for the greater integration of intermittent renewable resources. And, throughout time, combustion turbine technology will continue to serve the system in the future, whether it's fired with natural gas or another lower or non-carbon emitting fuel, such as hydrogen.

The 2020 IRPs demonstrate that a diverse mix of resources is needed to meet growing system demand and to replace the energy and capacity from retirements of older less efficient units. Planning for a mix of complementary new low- or no-carbon resources and reliable and proven dispatchable technologies, such as natural gas, is critically important for ensuring reliability and de-risking the transition as compared to a transition that relies on a single or narrow scope of technologies.

Q. PLEASE EXPLAIN WHY NATURAL GAS TECHNOLOGIES ARE AN IMPORTANT BRIDGE TO A NET-ZERO CARBON FUTURE?

A. As shown in the 2020 IRPs, adding incremental natural gas resources enables the earlier retirement of coal generating assets and facilitates the addition of significant amounts of intermittent solar resources, more cost effectively that other resources. Natural gas resources have a significantly lower carbon intensity than the coal units they are replacing, and play an important role in the transition to net-zero carbon emissions. Natural gas resources are efficient, reliable and affordable and continue to be required to meet customer demand into the future.

The Companies' 2020 IRPs demonstrate and plan for integrating renewable energy resources such as solar and wind to become increasingly important components of a net-zero carbon future. However, as Witness Roberts explains, these intermittent resources simply are unable to reliably meet customer demand each hour of each day of the year in a manner that dispatchable natural gas resources can. Witness Roberts details how planning to rely solely on renewable resources puts customers in great risk of NERC Reliability Standard violations and reliability failures in times when renewables do not or cannot produce (rainy/snowy days, dense cloud cover, etc.). Witness Roberts also demonstrates that while solar coupled with storage helps to some extent, the same general issues hold true. Batteries cannot be charged by a co-located solar facility that is not producing energy. As Witness Roberts, explains, the recent grid crisis in the ERCOT region in Texas shows multiple days with limited irradiance[85] and minimal wind speeds that severely limited solar and wind energy generation output for several days. My Figure 8 below shows the low output from solar (yellow line) and wind (green line) across multiple days during the recent extreme weather event in ERCOT, and

[85] Witness Roberts explains the concept of irradiance, at page 18 of his rebuttal testimony.

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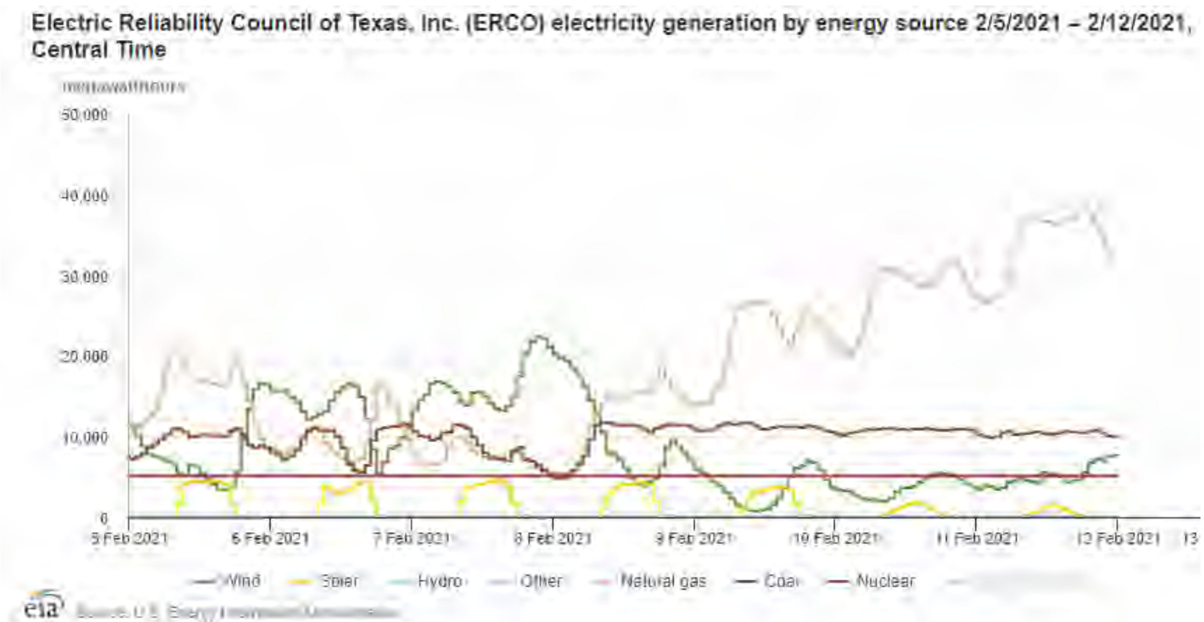
demonstrates the significant drop off in solar and wind generation availability that occurred.

Snider Rebuttal Figure 8



I do not make this point to criticize any of these technologies, but, instead, to highlight from a resource planning and system operations perspective that this real-world event calls into question the reliability contribution and value of storage of any duration that is being charged exclusively on renewable energy.

Q. CAN YOU PROVIDE REAL WORLD EXAMPLES OF THE CRITICAL ROLE OF NATURAL GAS GENERATION ON THE COMPANIES' SYSTEMS TODAY?

A. Yes. The Companies have become a national leader in install solar capacity. We can see the impact of that today on our system, and the need for flexible, dispatchable, and firm generation will likely be exacerbated as more solar is added to the system. Dispatchable natural gas is needed today and will be needed in the

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future to supplement additional solar resources due to the fact that customer demand, at the time of the DEC and DEP system peaks, is not correlated with solar generation output in the Carolinas. Winter peak demand occurs early morning, when little to no solar energy is available or reliably dependable. Natural gas resources are also needed to back stand renewables, to ensure reliable service in a variety of hourly, daily and weekly conditions. My Figures 9 and 10 below are examples of the role of natural gas in the DEP service territory, serving both as flexible ramping resources, and back standing low solar output. Battery storage can help, but as pointed out above, limitations of battery storage mean it can only be part of the solution. The important point to recognize is that the future will call for a range of technologies that will evolve over time, including renewables, storage, as well as proven dependable and dispatchable resources such as natural gas.

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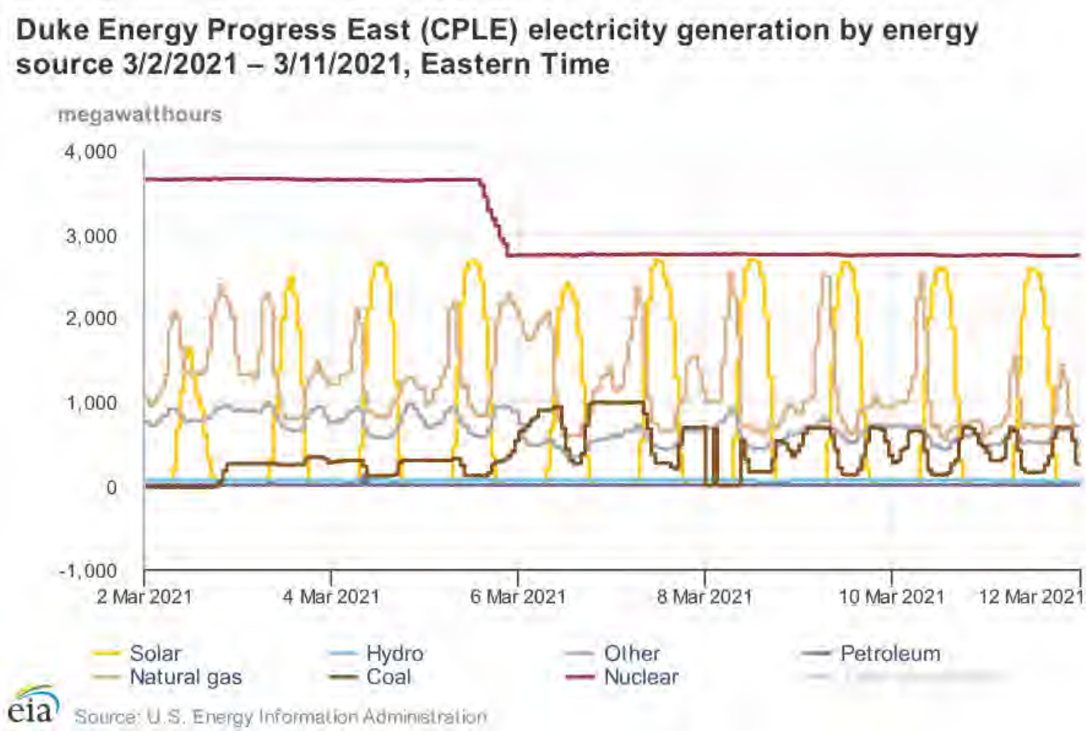
Snider Rebuttal Figure 9



Snider Rebuttal Figure 10

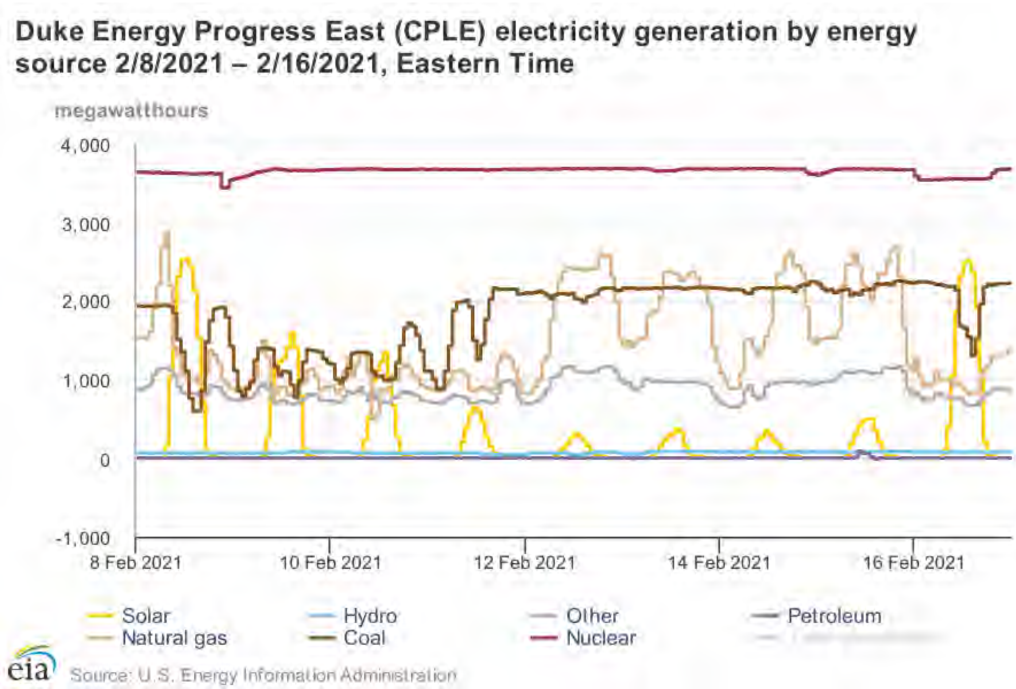


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Figure 10 shows the role of natural gas as a flexible compliment to intermittent resources such as solar. The generation profiles show that gas must ramp up in the Carolinas several hours before solar output starts, turn down as solar output climbs during the day, and then come back on or turn up in the evening as the sun sets. Storage can help with the shifting of energy to curtail peaks and reduce ramps. However, in periods such as those in Figure 10, during periods of low solar peak output, gas becomes a valuable back stand to solar. This time of high load and low solar output means that batteries charged exclusively on solar would not have been able to fill the demand in the Carolinas. It should be noted that the data presented in Figure 10 reflects the same period as the events in ERCOT and shows the value that gas provided to the system when solar output was reduced.

Q. HAVE YOU REVIEWED WITNESS FITCH'S DIRECT TESTIMONY?

A. Yes, I have reviewed Witness Fitch's direct testimony as well as his report entitled Carbon Stranding: Climate Risk and Stranded Assets in Duke's Integrated Resource Plans ("Carbon Stranding and Climate Risk Report") published by the Energy Transition Institute.[86] Witness Fitch heavily criticizes the Companies' 2020 IRPs and erroneously claims that for the Companies' to comply with Duke Energy's stated carbon reduction goals, stranded fossil resources including new natural gas resources will necessarily result creating significant cost risk for customers.

Q. WHAT ARE YOUR OVERALL IMPRESSIONS OF HIS ANALYSIS?

A. Witness Fitch inflates the risks of meeting load growth and filling coal retirements

[86] Vote Solar Fitch Direct, at Exhibit TF-2.

with natural gas generation through unreasonable and flawed technical assumptions and calculations. His report minimizes the holistic view of natural gas, including the affordability and reliability benefits of this resource, while simultaneously omitting the holistic view of the commensurate risks of other technologies that would be needed if natural gas was omitted from the transition plan.

Q. WHAT DO YOU BELIEVE WITNESS FITCH ATTEMPTS TO ACCOMPLISH WITH HIS ANALYSIS?

A. Witness Fitch says he believes "this overview is helpful for understanding the order of magnitude of climate-related risks and the substantial implications for the Companies' plans, assets, and operations in to [sic] the future."[87] However, he presents arguments based on flawed inputs and operational assumption data and flawed criteria for deeming costs stranded. He also overstates the costs using different asset lives and a discount rate inconsistent with the utility view as presented in the 2020 IRPs.

Q. AT A HIGH LEVEL, WHAT FLAWS DO YOU SEE WITH WITNESS FITCH'S ANALYSIS OF CARBON STANDING RISKS?

A. Witness Fitch's Carbon Stranding and Climate Risk Report and corresponding discussion in his direct testimony is fatally flawed on several fronts. Contrary to Mr. Fitch's assertions and analysis, natural gas assets will not be "stranded" under the 2020 IRPs. This is because natural gas units were reasonably modeled based on their appropriate lifespan and because cost-effective use of gas units will reduce emissions and help meet the Companies' corporate climate goals while maintaining

[87] Vote Solar Fitch Direct, at 20.

power system reliability. As I have stated, Witness Fitch does not share the same responsibility as the Companies for the provision of reliable energy that not only achieves environmental goals but that is also affordable for customers. Furthermore, his analysis generally does not have to stand up to regulatory scrutiny in the manner that the Companies' resource plans do which leaves him free to draw conclusions based on inaccurate and unrealistic assumptions. Transitioning the fleet away from coal and meeting future load growth in the Carolinas without building new gas units, as shown in the 2020 IRPs is the most expensive option for our customers and will likely require coal units to operate longer. It would also present technology risks and challenges to reliability that could impact customers.

Q. DOES WITNESS FITCH USE PRODUCTION COST MODELING SOFTWARE TO PROJECT THE FUTURE OPERATIONS OF THE COMPANIES' GENERATION FLEETS?

A. No, in his analysis, Witness Fitch does not use production cost modeling software to project the future operations of the generation fleet, which leads to inaccurate generation and emissions projections, used as the basis of his analysis.

Q. PLEASE EXPLAIN.

A. In his analysis, Witness Fitch, unreasonably assumes coal and natural gas will generate the same in the future as they did in the past. Witness Fitch uses historical generation and emission rates of units as a proxy for the future operations of the companies' fossil generation fleet. Essentially, he assumes that a coal or a gas unit will perform the same in 2050 as it did in 2016-2018. This assumption is baseless and grossly inaccurate. Looking back over the last few years, more renewable

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generation has been brought online, as well as more efficient natural gas generation, and the Companies' most efficient coal plants have been retrofitted with co-firing capability to increase their flexibility, de-risk fuel costs, and generate electricity with a lower carbon intensity. As the Companies' plan for the future, this type of trend will hold true, and older, less efficient generation will see their role reduced, as more renewable and efficient generation comes online, displacing units with emissions.

Q. WHAT CRITERIA DOES WITNESS FITCH USE TO DEEM A COST AS STRANDED?

A. Witness Fitch measured "stranded cost" as the unrecovered remaining book value of the unit in question at the time the unit is arbitrarily deemed unable to run as explained below. Witness Fitch's criteria for the determination of when a unit will be prohibited from operating (and hence "stranded"), is based on an arbitrary assumption of a declining carbon emissions cap. As Witness Santoianni for the Companies details, this carbon cap is based on a simplistic straight-line reduction from 2020 to zero emissions in 2050. His analysis deems a fossil unit unable to operate and therefore "stranded" when the projected emissions, based on historical operations, causes the fleet to exceed that year's annual "cap."

Q. WHY IS THIS SIMPLISTIC STRAIGHT-LINE ASSUMPTION SO UNREASONABLE?

A. Not only is this assumption overly simplistic, but it does not reflect the reality of how carbon regulations are likely to evolve, as Witness Santoianni explains, nor does it reflect the Company's path to "net-zero." The Companies recognize that factors outside of the Companies' control may impact year-to-year emissions, while Witness Fitch's analysis uses a hard and fast rule that is not truly reflective of the Companies' path to net-zero. Additionally, Witness Fitch's straight-line approach from 2020 to absolute zero by 2050 is troublesome. With this forecast, Witness Fitch clearly ignores the Companies' 2030 goal of 50% reduction, as discussed in the 2020 IRPs. This omission is significant, as the Companies' planned annual emissions reductions from 2020 to 2030 are more gradual than the rate of reduction projected later in the 2030s and 2040s. This is because deep decarbonization (particularly for utilities that are already national leaders for the provision of low carbon energy) can only be made possible through significant advancement of technologies, such as long duration storage, carbon capture, utilization, and sequestration (CCUS), hydrogen, RNG, off-shore wind and small modular and advanced nuclear reactors.

Q. ARE THERE OTHER ERRORS OR MISLEADING ASSUMPTIONS IN WITNESS FITCH'S CARBON STANDING ANALYSIS?

A. Yes. Mr. Fitch makes errors in his book life and discount rate assumptions and erroneously uses a levelized cost of energy ("LCOE") comparison in a manner inconsistent with sound resource planning principles.

Q. PLEASE DISCUSS MR. FITCH'S ERROR IN CALCULATING THE BOOK LIFE FOR THE COMPANIES' GENERATING UNITS.

A. The Carbon Stranding and Climate Risk Report estimates stranded costs through 2075, using a 40-year book life for all units added to the portfolio through 2035.[88]

[88] See Carbon Stranding and Climate Risk Report, at p 45.

Mr. Fitch's analysis assesses stranded costs as any remaining asset value after the emissions cap is exceeded. This is also an inaccurate representation of the 35-year book life of the gas assets planned for in the 2020 IRPs.[89] Relying on this incorrect assumption inflates the period of purportedly stranded costs by extending the useful lives of units past their projected retirement dates.

Q. PLEASE DISCUSS THE INCORRECT DISCOUNT RATE ASSUMPTION MR. FITCH USES IN HIS ANALYSIS.

A. Mr. Fitch postulates using discount rates that are inappropriate when looking at a utility view of the power system, such as in the 2020 IRPs.[90] Discount rates in the 2020 IRPs are approximated by the Companies' respective Weighted Average Cost of Capital (WACC), as the IRP is an industry standard utility view of reliably and cost effectively planning the system.

Q. PLEASE DISCUSS THE INACCURATE LEVELIZED COST OF ENERGY ASSUMPTIONS THAT MR. FITCH'S USES IN HIS ANALYSIS.

A. The Carbon Stranding and Climate Risk Report also discusses the cost comparison of new natural gas generation to that of renewables.[91] Witness Fitch cites a LCOE study for this argument.[92] While this simplified number may be appropriate for use in screening specific resources with similar operational characteristics, it is not at all useful for comparing resources with disparate characteristics. Intermittent energy-limited renewable resources that do not provide capacity should not be

[89] *See* DEC IRP, at 172; DEP IRP, at 171.
[90] *See* Carbon Stranding and Climate Risk Report, at 48.
[91] *Id.* at iv.
[92] *Id.*

compared on an LCOE basis to fully dispatchable resources that are capable of extended dispatch. This common mistake is often made by parties that are attempting to show costs of one resource as more beneficial than that of a more operationally-reliable resource with a higher capacity factor. Measuring the cost impacts of the entire system to determine how a resource performs on an hour-by-hour basis in a production cost model is ultimately a much more robust approach, as the Companies undertook in developing the 2020 IRPs.

Q. DID THE COMPANIES ALSO IDENTIFY OTHER ERRORS IN MR. FITCH'S ANALYSIS SUPPORTING HIS CARBON STRANDING AND CLIMATE RISK REPORT?

A. Yes. Witness Santoianni and Witness Roberts both identify factual errors and inconsistencies in Witness Fitch's analysis in their respective testimonies. These among other factors further compound the misleading technical components underlying his erroneous conclusions.

Q. WITNESS FITCH GOES OUT OF HIS WAY IN HIS ANALYSIS TO POINT OUT RISKS WITH NATURAL GAS RESOURCES.[93] DOES HE ALSO RECOGNIZE OR PRESENT RISKS ASSOCIATED WITH SOLAR, WIND, OR BATTERY RESOURCES IN THE IRP?

A. He does not. From the Companies' technically objective perspective, all evaluated technologies in the IRP involve future risk when looking out over multiple decades. As mentioned previously in my testimony, it is important to look at the holistic impacts of all technologies with respect to the guiding principles in Act 62.

[93] See Vote Solar Fitch Direct, at 19, 23, 26, 78, 81.

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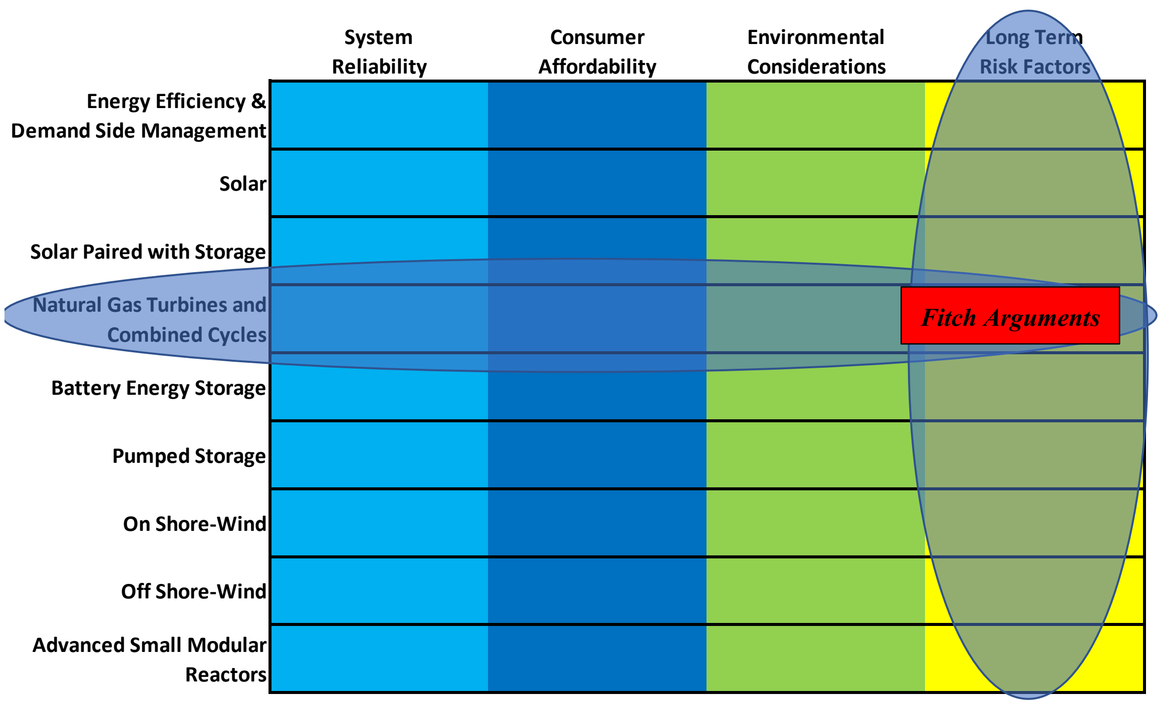
Resources must not only be evaluated on a single attribute, but the spectrum of potentials costs and benefits they may provide. Likewise, when considering factors that represent a reasonable and prudent plan, this broader holistic approach is required. The figure below again highlights this holistic view. Witness Fitch's Carbon Stranding and Climate Risk Report puts exaggerated focus on this one small area, while the Companies are charged with looking at the whole picture to provide South Carolinians with reliable affordable, and increasingly clean energy for decades to come.

Snider Rebuttal Figure 11: Singular Focus of Fitch's Opposition to Natural Gas



The Companies' IRPs are intended to show the benefits and costs of these technologies to the system based on the best information available at the time the IRPs were prepared. However, like any planning or forecasting process, the IRP cannot be expected to fully capture all risks that may occur thirty years from now nor does it attempt to do so.

Q. FROM A HOLISTIC PERSPECTIVE, WHAT ARE SOME OF THE RISKS THAT WITNESS FITCH'S CARBON STRANDING AND CLIMATE RISK REPORT AND TESTIMONY OMIT OR FAIL TO HIGHLIGHT EQUALLY?

A. When looking out over multiple decades, no resource is without risk which highlights the benefits of a diverse portfolio that incorporates an array of resources over the planning horizon. Solar, for instance, is a technology that has only in the last decade become a meaningful contributor to the electricity sector. Rapidly expanding adoption of new technologies introduces cost risk. As stated earlier in my testimony, solar early adoption paired with policies that did not have disciplined approaches to solar volumetric limits over time has resulted in approximately $170 million in "solar stranded costs" in 2020 alone. This is in addition to the projected future customer overpayments of over $2 billion by the end of the planning horizon.

From an operational perspective, at high solar penetration levels, significant emerging storage resources will be required to time shift solar energy at each time step from minutes, to hours, to days, to weeks, or even months at a time, leaving exposure to curtailment or price spikes with other technologies. Battery energy storage systems likewise harbor long-term risks when looking out multiple decades. Stranded cost risk due to the potential for changing battery chemistries, performance degradation uncertainty, global supply chain uncertainties, lifecycle costs uncertainties and disposal or recycling costs are all highly questionable uncertainties as power producers, the transportation sector, and residential customers all compete for the supply-chain for this resource.

Q. FROM A TECHNICALLY OBJECTIVE AND HOLISTIC PERSPECTIVE, DO OTHER TECHNOLOGIES ALSO HAVE RISKS TO BE CONSIDERED?

A. Yes. As contemplated in Appendix A of the IRP, with respect to the higher carbon reduction portfolios, offshore wind and new advanced nuclear also carry technology and execution risk, along with permitting costs risks, ecological and tourism impacts, and differing stakeholder perspectives.

As Witness Fitch points out, the carbon emissions associated with natural gas generation carries energy policy risk exposure and unknown costs to co-fire with a zero GHG emissions fuel, or other carbon recovery options to mitigate risk.[94] The Companies recognize all of these risks, which is why IRPs are routinely updated and changes to costs, policy risks and technology risks are evaluated, and included as appropriate.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS IN RESPONSE TO WITNESS FITCH.

A. Witness Fitch's Carbon Stranding and Climate Risk Report is overly simplistic, based on inaccurate information and it fails to recognize this broader holistic perspective. As a result, he reaches erroneous conclusions which only serve to obfuscate this proceeding and hamper real progress.

[94] *See* Vote Solar Fitch Direct, at 65, 78-80, 82.

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Witness Santoianni, Witness Roberts and I point out in our testimonies that natural gas resources paired with renewables, storage and other emerging technologies offer the potential to balance reliability, affordability, and the environment as the Companies transition to a net-zero carbon future. To be abundantly clear I bring up potential risks of other technologies not to discredit the technologies or their potential to serve an important role in decarbonizing the electricity sector, but to highlight that a broader perspective must be shared on all technologies and trade-off's must be understood when making decisions on how to transition the fleet.

Finally, if the electricity sector is not reliably and cost effectively transitioned to a net-zero future, then the sector will not be able to supply the backbone required for the decarbonization of the rest of the economy. The future decarbonization of the transportation sector, residential and commercial space heating and water heating needs, as well as the electrification of various industrial processes are all dependent on keeping electricity reliable and affordable to all customers throughout this industry transition.

2. <u>The Companies are Providing Additional Justification for Battery Energy Storage System Costs as Recommended by ORS</u>

Q. ORS RECOMMENDS THE COMPANIES PROVIDE ADDITIONAL JUSTIFICATION FOR THEIR BATTERY ENERGY STORAGE FIXED O&M COST AND CAPACITY FACTOR ASSUMPTIONS. HOW DO YOU RESPOND TO THIS RECOMMENDATION?

A. The Companies agree that their Fixed O&M Costs are initially immaterially higher than other projections, but align with the other projections over the planning horizon. Witness Kalemba further discusses this issue in his testimony.

The Companies maintain that the capacity factor assumptions, as a result of the production cost model, are appropriate given the needs of the system. The capacity factor for batteries generally represent one cycle per day for a 4-hour battery, a reasonable assumption. In scenarios with higher penetrations of batteries, average capacity factors tend to decline as the opportunity for energy arbitrage for batteries becomes more saturated. It should also be noted that existing pumped storage plays a significant role in the selection and operation of energy storage and shifting, especially in DEC.

3. The Companies' 2020 IRPs Appropriately Evaluate Solar as Energy-Only Resource Option and CCEBA's and ORS's Recommendation to Follow the DESC Order and Require Modeling of Solar PPAs Would be "Apples-to-Oranges" and Would Not Fairly Evaluate Solar As Required by Act 62

Q. DO YOU AGREE WITH CCEBA WITNESS LUCAS'S RECOMMENDATION THAT, "DUKE SHOULD ALLOW THE ADDITION OF NEW RESOURCES OR PPAS EVEN WHEN THERE IS NOT A CAPACITY NEED, AS WAS REQUIRED IN THE DESC IRP ORDER"[95]?

A. The Companies agree with Witness Lucas's recommendation to the extent he is focused on evaluating the cost-effectiveness of energy-only resources. In fact, the Companies employed this concept in developing their 2020 IRPs. Energy-only resources refer to resources that are not able to fill a capacity need but are available to reduce energy needs.

[95] CCEBA Lucas Direct, at 6.

PUBLIC (REDACTED) VERSION

Q. WHY IS STANDALONE SOLAR APPROPRIATELY MODELED AS AN ENERGY-ONLY RESOURCE?

A. Standalone solar (solar not paired with storage) contributes one percent or less of its capacity towards the winter capacity planning reserve margin; as such it is almost wholly an energy-only resource. From a planning perspective, solar is not a substitute for dispatchable capacity resources in an IRP as it cannot meet growth in winter peak demand nor can solar replace retiring coal generation that currently meets winter peak demand needs that occur in non-daylight hours. However, solar resources can serve to reduce marginal system energy needs during daylight hours and the associated fuel consumption of the energy it is displacing. This is why standalone solar is referred to as an energy-only resource which is selected in the expansion model when it can economically displace daytime energy produced from the systems marginal generator irrespective of system capacity needs. To illustrate this point, the DEC capacity expansion run for Base Case with Carbon Policy begins to economically select additional solar in DEC in 2025, a year in which there is no capacity need. Accordingly, the Companies agree, to an extent, with Witness Lucas's recommendation to consider procuring additional, undesignated standalone solar (i.e., over and above what is required to meet policy mandates) when it begins to be economically advantageous for our customers to do so.

Q. ORS AND CCEBA RECOMMEND THAT THE COMPANIES INCLUDE AN ADDITIONAL SOLAR GENERIC RESOURCE OPTION IN THEIR MODELING ASSUMPTIONS THAT REFLECTS THE KIND OF SOLAR PPA PRICE THAT MAY BE AVAILABLE IN THE MARKET. DO YOU

BELIEVE A "20-YEAR SOLAR PPA" RESOURCE OPTION SHOULD BE ADDED TO THE MODEL?

A. No, I do not. In resource planning, it is important that all potential resource options are available to be equally selected by the model, with no one resource option being treated preferentially as compared to the others. This fundamental resource planning concept was adopted in Act 62, which requires the Companies to "fairly evaluate the range of demand-side, supply-side, storage, and other technologies and services available to meet the utility's service obligations."[96] The model treats the generic solar option like all other technology options by evaluating the cost over the planned operating or useful life of the resource.

Specific to the generic solar option, the model includes the cost of that resource over the full 30-year life of the asset. In contrast, under the solar PPA option recommended by ORS and CCEBA, the Companies model would only include the cost of the purchased power contract over a 20-year period.

Q. DOES MODELING A SOLAR PPA PRICE IN THIS MANNER CREATE A FAIR EVALUATION OF SOLAR PRICING COMPARED TO OTHER TECHNOLOGIES AS REQUIRED BY ACT 62?

A. No. Following this approach would create an unequal and unfair comparison among generation resources options in the model for several reasons. First, and most obviously, the cost of the PPA option only represents the costs for the first 20 years of the asset. It is not possible to know the cost of that PPA option over the 30-year useful life of the facility. The cost of the PPA included in the first 20 years

[96] S.C. Code Ann. § 58-37-40(B)(1)(e).

could be two-thirds of the total cost or it could be one-third of the cost—it is impossible to know how a third-party owner would have the transaction structured and how much "residual value" the generator owner and its investors are counting on receiving from customers after the initial 20-year PPA term. For example, if a CO_2 tax or some other form of climate policy is enacted over the initial 20-year period, then the subsequent contract period (years 21-30) presents significant value potential for the solar developer not factored into avoided cost today. This potential "residual value" for the developer represents an associated cost risk for customers, as they will be exposed to future, potentially much higher, PPA prices as solar PPAs will be priced at the then prevailing market for energy (and, likely CO2 allowances). In order to appropriately model this theoretical resource in an IRP on an equal footing, the Companies would need to estimate future PPA costs for the ten-year period after the original 20-year PPA expired under a CO_2 policy portfolio that would account for this risk to customers. My Figure 12 demonstrates how a seemingly lower-cost 20-year PPA would be modeled over a fixed levelized term, but could result in increased costs for customers due to the unknown 10-year tail period, as compared to standard cost-of-service based modeling of costs over the full 30-year life of the solar asset.

PUBLIC (REDACTED) VERSION

Snider Rebuttal Figure 12: Demonstrating Post Term Cost Risk of Modeling 20-Year PPA Compared to Utility Revenue Requirement

Q. DO THE COMPANIES ALREADY INCLUDE SOLAR PPA RESOURCES IN THE MODEL?

A. Yes, the Companies already model significant contracted for and designated solar pursuant to PPAs under PURPA, CPRE, Act 62, and the Green Source Advantage Programs being developed in both South Carolina and North Carolina. Because these PPAs are "forced" into the model, instead of being economically selected, they do not create the same "apples-to-oranges" comparison as what I have described above. As discussed in the 2020 IRPs, it is appropriate to force these resources into the model because the Companies are required to purchase their output pursuant to state and federal laws.

PUBLIC (REDACTED) VERSION

Q. SHOULD THE FACT THAT THE COMMISSION ORDERED DESC TO EVALUATE THIS SOLAR PPA OPTION HAVE ANY BEARING ON THE COMMISSION'S DECISION-MAKING IN THESE PROCEEDINGS FOR DEC AND DEP?

A. No. As I mention in the presentation of my general observations above, DEC's and DEP's IRPs should be considered on their own merits and the Commission's factual determinations and directives in the DESC Order should have no bearing on the Commission's decision-making in these proceedings. In fact, this issue provides a good example of how the Companies and DESC seemingly took different approaches to developing their IRPs such that the Commission's determination in the DESC IRP proceeding is completely inappropriate for DEC and DEP.

While I have not extensively reviewed DESC's 2020 IRP or their underlying modeling approach, my review of the DESC Order suggests that DESC's IRP included a 20-year solar PPA as a resource option.[97] This assumption was apparently based on the NREL ATB medium price projections; however, the Commission found that this levelized pricing was "demonstrably unrealistic" and that improvements should be made to use lower costs solar PPAs based on likely solar PPA costs available through recent competitive procurements in South Carolina.[98] Accordingly, the DESC Order rejected this assumption and directed DESC to rerun its model based on adding 400 MW of incremental solar at three 20-

[97] Order No. 2020-832, at 47, *In re South Carolina Energy Freedom Act (House Bill 3659) Proceeding Related to S.C. Code Ann. Section 58-37-40 and Integrated Resource Plans for Dominion Energy South Carolina, Incorporated*, Docket No. 2019-226-E (2020).
[98] *Id.* at 49.

year PPA price various lower price sensitivities. It is unclear why DESC found it methodologically appropriate to model a 20-year solar PPA, at any price. However, the key point is that the issues in contention in the DESC proceeding were quite different than the issues here.

To reiterate, the Companies are not similarly situated to DESC, whom the Commission found did not use industry-recognized capacity expansion modeling software in preparing its 2020 IRP, a deficiency that the Commission found did not comply with industry best practice.[99] The determinations made by the Commission were based on the information, facts and circumstances the Commission had in the record in that proceeding. The Commission has a completely new set of facts and circumstances on the record in these proceedings, which requires an independent determination from the Commission based on the record in this case.

4. The Companies are Providing the Information Recommended by ORS to Clarify Whether Renewable Resources were Forced-In or Economically Selected

Q. DOES ACT 62 REQUIRE THE COMPANIES TO ADDRESS RENEWABLE TECHNOLOGIES AS PART OF THEIR IRPs?

A. Yes. Act 62 requires utilities to provide several resource portfolios developed with the purpose of fairly evaluating the range of demand-side, supply-side, storage, and other technologies. The Act directs that those portfolios *must* include "an evaluation of low, medium, and high cases for the adoption of renewable energy and cogeneration[.]"[100]

[99] *Id.* at 16.
[100] S.C. Code. Ann. § 58-37-40(B)(1)(e).

PUBLIC (REDACTED) VERSION

Q. DOES ORS SUPPORT THE COMPANIES' APPROACH TO CONSIDERING RENEWABLE TECHNOLOGIES, AS PRESENTED IN THE 2020 IRPs?

A. Yes**.** ORS notes that the Companies' provided "detailed economic evaluations of [their] six (6) Portfolios [that] considered several types of renewable resources including, Solar, Battery Energy Storage, Solar plus Battery Energy Storage, Offshore Wind, Central-US Wind, and PSH."[101]

Q. DOES ORS PRESENT ANY RECOMMENDED IMPROVEMENTS TO BE ADDRESSED IN MODIFIED OR FUTURE IRPs?

A. Yes. ORS recommends the Companies provide a table identifying each renewable resource option that was modeled, and describe whether the resource was forced-in or economically selected, the reason the resource was forced-in, whether the resources is a designated, mandated, or undesignated resource, and where the resource is found in the PROSYM database and in the LCR tables for reconciliation purposes

Q. HOW DO THE COMPANIES RESPOND TO THIS RECOMMENDATION?

A. The Companies agree to provide this information as an Exhibit to DEC/DEP Witness Kalemba's Testimony.

[101] ORS Sandonato Direct, Exhibit AMS-1, at 78, Exhibit AMS-2, at 77.

PUBLIC (REDACTED) VERSION

5. The Companies Agree to Address Solar Capacity Value Assumptions in a Stakeholder Proceeding, as Recommended by ORS

Q. ORS RECOMMENDS THAT FURTHER INVESTIGATION BE CONDUCTED REGARDING SOLAR CAPACITY VALUES AND SOLAR PLUS BATTERY ENERGY STORAGE CAPACITY VALUES WITH STAKEHOLDER INPUT VIA DISCUSSIONS AS PART OF A STAKEHOLDER ENGAGEMENT PROCESS. PLEASE RESPOND TO THIS RECOMMENDATION.

A. The capacity value assumptions for solar and solar plus battery energy storage used in development of the 2020 IRPs were based on studies conducted by Astrapé Consulting.[102] These studies reflect the same high level of methodological sophistication as recognized by ORS in their review of the 2020 Resource Adequacy Studies, also conducted by Astrapé. The purpose of these studies was to develop quality capacity value planning assumptions for use in the future IRP process. The Companies agree to review these values as part of the IRP stakeholder process. DEC/DEP witness Kalemba provides further comments regarding this recommendation in his rebuttal testimony.

[102] Astrapé completed the Solar Capacity Value Study for DEC and DEP in 2018 and completed the Storage ELCC study in 2020. Astrapé also completed Resource Adequacy Studies for the Companies in 2020. Nick Wintermantel, Principal Consultant and Partner at Astrapé Consulting, is providing expert witness testimony in this proceeding on behalf of the Companies.

Q. FURTHER, ORS RECOMMENDS ONE INVESTIGATION THAT COULD BE PERFORMED WOULD BE TO ASSESS THE IMPACT ON THE COMPANIES' BASE CASE RESOURCE PLAN IF HIGHER WINTER CAPACITY VALUE RATINGS WERE ASSUMED SUCH AS 5% FOR SOLAR AND 30% FOR SOLAR PLUS BATTERY ENERGY STORAGE. DO YOU AGREE WITH THIS RECOMMENDATION? WHY OR WHY NOT?

A. I agree that this investigation could be performed, but obviously higher winter capacity value assumptions for solar and solar plus battery energy storage would shift the need for other capacity resources to a later date. This investigation, or sensitivity, represents one of numerous sensitivities that the Companies could consider in the IRP; however, care must be taken to ensure the IRP process does not become too unwieldy. The Companies plan to periodically conduct new ELCC studies to ensure appropriate planning assumptions for use in the IRP. DEC/DEP Witness Kalemba provides further comments on this topic in his rebuttal testimony.

Q. HOW DO YOU RESPOND TO CCEBA WITNESS OLSON'S RECOMMENDATION TO UPDATE THE SOLAR CAPACITY VALUE STUDY TO REFLECT THE DEMAND REDUCTION POTENTIAL NOTED IN THE WINTER PEAK DEMAND REDUCTION POTENTIAL ASSESSMENT REPORT?

A. As I previously noted, Astrapé completed the Solar Capacity Value Study for the Companies in 2018. The study was based on the demand reduction projections that were current at that time. These types of studies are very complex and take significant time to produce. While it is not practical to update the study every time an input assumption changes, these types of studies will be periodically updated to reflect changes in input assumptions.

It is important to realize that the incremental demand reduction potential identified in the Winter Peak Study will not be fully realized until 2041. Thus, the incremental demand reduction is projected to slowly ramp up to these levels over the next 20 years. It is illogical for the Companies to assume 2041 demand reduction projections when assessing near term resource needs in the IRP.

Q. MR. OLSON CLAIMS THAT MORE DEMAND RESPONSE CAPACITY IN THE WINTER WOULD MOVE LOLE TO THE SUMMER, INCREASING THE CAPACITY VALUE OF SOLAR. DO YOU AGREE?

A. Technically, Mr. Olson is correct; however, again his comments are misleading.

Q. PLEASE EXPLAIN.

A. As part of the 2020 Resource Adequacy Study, Astrapé performed a sensitivity that increased winter demand response potential. Even with this change, the reliability risk was still heavily concentrated in the winter and there was not a material shift of risk to the summer. Further, even if there was a small shift of reliability risk to the summer, the Companies would still be winter planning and such a shift would not change the winter capacity value of solar which is very small. Mr. Wintermantel addresses the demand response sensitivity in greater detail in his rebuttal testimony.

6. <u>The Companies Appropriately Accounted for the Synergies Between Solar and Battery Storage in Their 2020 IRPs</u>

Q. WERE THERE ANY AREAS OF AGREEMENT WITH CCEBA WITNESS OLSON REGARDING THE ELCC METHOD TO VALUE SOLAR PLUS STORAGE?

A. Yes, witness Olson "strongly agrees with the use of the ELCC method, which more accurately reflects the capacity contribution provided by renewables and energy storage."[103] Further, Mr. Olson stated that "Duke should be commended for its use of ELCC, which has not yet been universally adopted by utilities across the country."[104]

Q. WHAT IS CCEBA'S POSITION REGARDING THE COMPANIES' TREATMENT OF RENEWABLE ENERGY AND ENERGY STORAGE IN THEIR RESPECTIVE IRPS?

A. CCEBA Witness Olson opines that the capacity expansion modeling used by the Companies does not adequately address the intermittent nature of renewables or the flexibility of energy storage systems. In particular, Witness Olson suggests that the Companies did not co-optimize solar and storage resources in a single step and argues that doing so—i.e., considering the value of renewable energy in a vacuum, separate and apart from storage capacity—devalues renewable options. In other words, Witness Olson suggests that the Companies' approach failed to accurately capture the synergistic effects of solar and storage, resulting in an artificial reduction in the amount of solar and storage to be built on the system.

[103] CCEBA Olson Direct, at 15.
[104] *Id.* at 15.

PUBLIC (REDACTED) VERSION

Q. DO YOU AGREE WITH WITNESS OLSON'S CHARACTERIZATION OF THE COMPANIES' OPTIMIZATION METHODOLOGY?

A. No. Witness Olson is correct that the Companies employed a sequential, rather than single step, approach to optimization. However, his characterization of the result—a purported devaluing of the solar capacity—is incorrect. He is actually supporting the need to use a robust production cost model to more accurately value storage compared to sole reliance on an expansion planning screening model. This is precisely why the Companies went through the more detailed approach as we explain in detail in Chapter 11 of the IRPs, and as further explained through extensive discovery and as detailed in my testimony.

It is true that the Companies evaluated the economic impact of batteries *after* the capacity expansion model selected replacement resources given the limitations of the portfolio optimization screening tools. However, batteries were robustly evaluated in the Companies' production cost model. As part of the modeling, the Companies replaced CTs that were economically selected in the portfolio development in the capacity expansion model with the equivalent firm amount of battery capacity, according the company ELCC study of batteries. The extra step of using the production cost model was to fairly evaluate the value of storage with the model that is better suited for storage valuation. Storage benefits can best be measured in production cost models that examine hour by hour dispatch of the system, and identify periods when storage should charge and discharge to lower the overall cost of the system. These nuances of chronology and high and low load hours are muted in the capacity expansion model, as the hour aggregation and simplification of the model is used to speed up processing time. The robust approach used by the Companies ensured batteries were given a fair evaluation in economic selection in the base case portfolios.

In short, Witness Olson's claim that the Companies have not captured the total synergistic effects of solar and storage by using the sequential modeling approach is incorrect.

Q. DO YOU AGREE WITH THE ELCC VALUES FOR SOLAR PLUS STORAGE DERIVED BY WITNESS OLSON?

A. No, I do not. Mr. Olson makes several illogical assumptions in his ELCC analysis in an effort to shift greater LOLE to the summer period in an effort to ascribe greater capacity value to solar and storage. For example, Mr. Olson assumes 2040 load and 2041 demand response projections to determine the ELCC of incremental solar and storage resources which is completely absurd. Witness Wintermantel and witness Kalemba address Mr. Olson's critiques in detail in their rebuttal testimony.

(F) The Companies' 2020 IRPs Appropriately Address Climate Change and Other Environmental Issues Within the Context **of Act 62 and the Companies' Commitment to Achieve Net-Zero Emissions by 2050; Intervenor Challenges Fail to Factor Affordability and Reliability into Their Analyses**

Q. DOES ACT 62 REQUIRE THE COMPANIES TO ADDRESS ENVIRONMENTAL ISSUES, AS PART OF THEIR IRPS?

A. Consideration of carbon dioxide emissions and other environmental issues is not expressly listed among the nine identified issues that must be addressed in a utility's IRP. Nevertheless, environmental considerations are implicated in many of the Act 62 factors. The Companies are also required to comply with a number of state and federal environmental regulations, which must be taken into account as part of the IRP process. Furthermore, we believe the IRPs support the Companies' corporate commitment, announced in 2019, to reduce CO_2 emissions by at least 50% from 2005 levels by 2030, and to achieve net-zero by 2050 our IRPs support that commitment. For all of these reasons, the Companies have robustly addressed environmental issues in their respective IRPs.

Q. DOES ORS SUPPORT THE COMPANIES' APPROACH TO ENVIRONMENTAL ISSUES, AS PRESENTED IN THE 2020 IRPs?

A. Yes. ORS and Kennedy Associates extensively examined the Companies' plans for meeting its own carbon reduction goals, as well as plans to meet applicable air and water quality regulations and found the Companies' approach to each to be "reasonable."

Q. DOES ORS PRESENT ANY RECOMMENDATIONS OF ISSUES TO BE ADDRESSED IN MODIFIED OR FUTURE IRPs?

A. Yes. ORS recommends that the Companies provide summary tables of the capital and operations and maintenance (O&M) costs for compliance with environmental regulations and descriptions of these costs.

Q. HOW DO THE COMPANIES RESPOND TO THIS RECOMMENDATION?

A. The Companies do not agree that O&M costs for compliance with environmental regulations should be included in future IRP filings. Such cost information is confidential to the Companies, and disclosure in the IRP filing could be harmful to the ratepayer. Instead, the Companies propose that ORS and other intervenors may request this information through the discovery process, where the Companies can make it available to parties who have signed non-disclosure agreements. That is the procedure the Companies have followed in the instant proceedings, providing many of their environmental compliance costs in confidential responses to ORS data request Nos. 2-19 and 2-21. This information is also being provided for the Commission's review in Confidential Snider Exhibit 10.

Q. DO ANY OF THE ADVOCACY GROUPS COMMENT ON CLIMATE CHANGE ISSUES?

A. Yes. Both CCEBA Witness Olson and Vote Solar Witness Fitch make recommendations for the Companies' IRP that implicate climate change issues.

Q. WHAT RECOMMENDATIONS DOES CCEBA WITNESS OLSON MAKE WITH RESPECT TO CLIMATE CHANGE?

A. Witness Olson opines that climate policy and climate change should be incorporated into the Companies' IRP process. He suggests that climate change implicates both technological and cost issues that the Companies should address in the IRP process, including by incorporating renewable energy and energy storage as potential resources.

Q. DO THE COMPANIES' IRPs ADDRESS CLIMATE CHANGE?

A. Yes, the Companies incorporate climate change in the IRP process in a variety of ways. With input from stakeholders, the IRP explores the opportunities and challenges over a range of options for achieving varying trajectories of carbon emission reduction. The 2020 IRP highlights six possible portfolios, or plans, within the 15-year planning horizon. These portfolios explore the most economic and earliest practicable paths for coal retirement; acceleration of renewable technologies including solar, onshore and offshore wind; greater integration of battery and pumped-hydro energy storage; expanded energy efficiency and demand response and deployment of new zero-emitting load following resources such as small modular reactors ("SMRs"). All pathways included in the 2020 IRP keep Duke Energy on a trajectory to meet its carbon goals over the 15-year planning horizon.

Q. WHAT RECOMMENDATIONS DOES VOTE SOLAR WITNESS FITCH MAKE WITH RESPECT TO CLIMATE CHANGE?

A. On a macro level, Witness Fitch argues that the Commission should wholesale reject the Companies' respective IRPs because they have not adequately integrated climate-related risks. Witness Fitch also argues that future IRPs should include (1) a systematic assessment of climate-related risks; (2) adoption of more strategies to manage climate-related risks; (3) explicit consideration of the Companies' anticipated zero-carbon transition; and (4) evaluation of its Plans that fairly considers long-term costs.

Q. HOW DO YOU RESPOND TO WITNESS FITCH'S RECOMMENDATIONS?

A**.** I disagree with Witness Fitch's recommendations**.** As I have already described, the Companies have adequately addressed climate change in this IRP by considering it, where applicable, in relation to the factors identified in Act 62. In fact, Witness Fitch's recommendation that the Companies should study and integrate climate risks in this and future IRPs is overbroad, unnecessary, and misplaced. DEC/DEP Witness Santoianni discusses the flaws of this recommendation extensively in her rebuttal testimony, noting that (1) it is generally the role of state and federal policymakers—*not* regulated utilities—to set climate change standards; and (2) in another docket, the Companies have already agreed with Vote Solar to study climate change and risk.

Q. WHAT SPECIFIC STEPS DOES WITNESS FITCH SUGGEST THE COMPANIES SHOULD TAKE TO ADDRESS CLIMATE CHANGE?

A. Witness Fitch recommends a variety of measures he contends the Companies should take to adequately address climate change, many of which are discussed at length in Witness Santoianni's testimony.

In addition, Witness Fitch recommends the Companies analyze and provide carbon price trajectories. While these prices are not drastically dissimilar to the trajectories used in the IRP, the IRPs prices start later, reflecting a more realistic timeline for a carbon tax or energy policy to be developed and implemented. Carbon prices in the IRP represent potential future carbon policies that would be strong enough to incentivize technologies to further decarbonize over the planning horizon without resulting in reliability disruptions or severe price shock. These energy policy proxies are consistent with the type of policies that may be needed to incentivize deep decarbonization pathways and consistent with the Companies' corporate climate goals.

Witness Fitch also recommends a suite of additional planning documentation, including Net-zero Transition plans for all IRPs, lifetime asset plans for new generation, and integrating all costs through 2050, and putting a heavier weight on these exceedingly more uncertain costs in the future, using a lower discount rate than the companies' weighted average cost of capital.

Having extensive detailed plans for 2050 on each asset in the IRP is not practical given the tremendous uncertainty in that time period with respect to every aspect of the IRP. Per my earlier testimony, his suggestion would need to apply to each resource type in the plan. This would result in an unproductive debate on what policies, technologies, economy wide shifts in energy usage, land usage, recycling plans, global supply chain shifts and numerous other factors that could be postulated for 2050. At this point, the Companies' use of an escalating carbon price that continues out in time is sufficient to capture the changing dynamics of the long-term markets. Recognizing the ongoing nature of the planning process variables that are uncertain further out in time will migrate from general qualitative assessments to more quantitative in nature as is the case with any planning process.

In the near term, Witness Fitch recommends several additions to the Short-term Action Plan including proposing to defer current planned generation, transmission, and distribution ("GTD") required to maintain and ready the system for reliable operations, in lieu of any project that might be able to be replaced with DERs. While the Companies continue to find opportunities to implement advanced GTD planning through the ISOP process, the Companies cannot simply press pause on maintaining a reliable system in favor of future possibility that a DER solution could compete with the currently identified solution. Witness Roberts will further expand on this topic in his rebuttal testimony.

Fitch goes on to recommend coordinating with the Commission on third party evaluations of EIMs, EEMs, and RTOs, and developing climate risk working group. These are largely outside the scope and purview of the IRP as Witness Santoianni explains in her rebuttal testimony.

Q. HOW SHOULD THE COMMISSION VIEW WITNESS FITCH'S RECOMMENDATIONS IN THE CONTEXT OF THE IRP?

A. While Witness Fitch has great interest in the Companies' Integrated Resource Plans, his analysis is narrowly focused and fails to weigh affordability, reliability, and the risk that certain technologies may result in higher costs to customers against the purported benefits of his clean energy proposal as the Companies are required to do under Act 62. The Companies take seriously their responsibility to continue to provide reliable, affordable, and increasing clean energy to their customers in South Carolina. Witness Fitch, as an employee and paid expert of Vote Solar—an advocacy group with the stated mission of transitioning the country's energy profile to majority solar by 2050[105]—does not share the same obligation to balance reliability and cost with Vote Solar's aggressive goals for the solar industry. His analysis draws bold conclusions, but as explained in Witness Santoianni's testimony, the data and methodology he relies upon are inherently flawed and largely dismissive of explicit modeling results in the IRP, as well as the discussions around risk mitigation and collaborative work with energy policymakers and stakeholders to drive towards an increasingly cleaner energy system together.

[105] *See* VoteSolar.org/about-us ("Our mission is to achieve a just and equitable transition to 100% clean power across the U.S. by 2050, with a majority of our energy coming from solar.") (last visited mar. 19, 2021).

PUBLIC (REDACTED) VERSION

(G) The Companies' 2020 IRPs Appropriately Value Energy Efficiency and Demand Side Management

Q. PLEASE REINTRODUCE THE ACT 62 REQUIREMENTS TO ADDRESS EE AND DSM, AS PART OF THE COMPANIES' IRPs.

A. Act 62 requires the Companies to address customer energy efficiency and demand response programs as part of the IRP resource portfolios.[106]

Q. DOES ORS SUPPORT THE COMPANIES' EVALUATION OF EE AND DSM, AS PRESENTED IN THE 2020 IRPs?

A. Yes. ORS addresses the Companies' portfolios of EE/DSM programs, comments that the Companies are reasonably focusing future DSM efforts on reducing winter peak demand, and highlights that the Companies score favorably in the upper quartile on the ACEEE State Energy Efficiency Scorecard rankings.[107]

Q. DOES ORS PRESENT ANY RECOMMENDATIONS OF ISSUES TO BE ADDRESSED IN MODIFIED OR FUTURE IRPs?

A. Yes.

Q. ARE THE COMPANIES PROVIDING THE ORS RECOMMENDED ADDITIONAL JUSTIFICATION FOR SELECTING THE BASE EE/DSM CASE AS OPPOSED TO THE HIGH EE/DSM CASE FOR USE IN PORTFOLIO A?

A. Yes. The company has provided additional justification for selecting the Base Energy Efficiency and Demand Response forecasts for including the company's base cases are included in Snider Exhibit 11.

[106] S.C. Code. Ann. § 58-37-40(B)(1)(e)(i).
[107] *See* ORS Report (DEC), at 44-45; ORS Report (DEP), at 44-46.

PUBLIC (REDACTED) VERSION

In addition to the testimony of Witnesses Bak and Herndon, I would add the perspective of how utility energy efficiency and demand response programs impact an IRP. Essentially utility sponsored energy efficiency programs reduce the load forecast allowing the utility to plan for lower energy and capacity levels as a result of projected savings from these measures. Since an IRP is a planning document that aims to accurately balance forecasted load net of EE with generating resources and DSM programs, we select the Base EE/DSM case because the measures and programs utilized therein represent technologies with positive cost effectiveness scores as this is our "best" estimate of the net load the Company will be required to serve over the planning horizon. Contrast this to a higher case that represents additional savings potential that are more aspirational in nature and more dependent upon future demonstration of potential savings that may be possible through yet to be Commission approved future EE/DSM offerings. While it is certainly the Companies' hope that it will be able to achieve these higher savings as it works with stakeholders to develop additional cost-effective programs, to present for Commission approval, it is premature to count on these additional savings for the base case analysis as it has the effect of increasing reliability risk through dependence on EE savings that have less certainty of achievement than the base case savings. It is important to note that as we move through time, if future potential savings become more certain through Commission approved programs, those savings will move into the base case in future IRPs. The testimony of Witness Bak along with that of expert Witness Herndon of Nexant Utility Services who address

EE/DSM in the Carolinas along with the recently completed Market Potential Study further address this topic.

Q. ORS RECOMMENDS THAT, IN ADDITION TO THE SENSITIVITY CASES DEVELOPED IN THIS IRP, THE COMPANIES ALSO EVALUATE HIGH AND LOW LEVELS OF EE/DSM USING HIGH FUEL/CO_2 AND LOW FUEL/CO_2 ASSUMPTIONS. DO YOU BELIEVE THIS INFORMATION SHOULD BE PROVIDED IN A MODIFIED IRP IN THIS PROCEEDING?

A. No. While I understand that the ORS may find this information of interest, I do not believe it should be required for the following three reasons.

- First, the information request from the ORS does not rise to the level of requiring a modified IRP.
- Second, it is important to understand if the additional analysis would produce meaningful or impactful results that would significantly change the IRP or results.
- Finally, consideration must be given to whether the request is consistent with the analysis called for in Act 62 or is a meaningful extension of the requirements in the Act.

With respect to the first issue, as I have stated, I believe the potential for the Commission to order the utility to file a modified IRP was intended to be reserved for instances in which the Commission determined that there were material or critical deficiencies in the IRP that required corrections. Clearly with this many parties to such a comprehensive IRP docket there will never be complete alignment on the numerous virtually infinite number of potential analysis that might be desired. As such, if the standard for filing a modified IRP is complete alignment on all issues, and the provision of all additional analysis requests, then the filing of modified IRPs will simply be the procedural norm as complete alignment is an impossible standard in the context of an IRP docket.

With respect to the second issue which asks if the request for additional analysis provides meaningful information that is not already viewed to some respect in the IRP, it is important to realize that the Company has already provided individual high and low sensitivity analysis on this variable. In addition, it has included the High EE/DSM case in three of the six portfolios analyzed. Complying with the ORS request for additional combinations of analysis to examine EE and DSM under combinations of fuel and carbon pricing creates an extraordinary amount of additional work that may be of limited value considering the analysis already performed on this variable.

Finally, with respect to viewing the request for additional analysis in light of the requirements of Act 62 it is important to understand that Act 62 does call for high and low sensitivities on certain individual input parameters such as fuel costs, environmental costs, technology costs, renewable penetration levels etc. However, requiring the combined analysis on these variables simultaneously under varying states of high and low outcomes for each individual variable simply becomes unmanageable.

PUBLIC (REDACTED) VERSION

Q. PLEASE DISCUSS THE PARTICULAR DIFFICULTIES IN ACCOMMODATING THE ORS'S REQUEST FOR THIS COMBINED VARIABLE ANALYSIS?

A. High and Low Levels of EE/DSM paired with other sensitivities present unique issues for performing sensitivities. While CO_2 and fuel price sensitivities may drive the selection of different resources, the quantity of higher or lower EE/DSM impacts changes the net load forecast and the capacity resource reserves available. To account for this, each sensitivity could effectively create a new portfolio for each scenario based on the resultant net load and required reserve margins. These changes to the portfolio would continue to make it more difficult to compare the impacts and interplay of other, more impactful variables.

When the companies look at the scope of the IRP, focusing concentration on the most impactful variables is paramount in order to provide policy makers with enough information while not overwhelming them with results that drive minor changes to the portfolio. As demonstrated in the sensitivity analysis, the higher EE/DSM parameters account for less than a 2% collective impact on total PVRR whereas other variables such as fuel prices, renewable technology prices, and load growth account for much higher cost variabilities. For these reasons, the Companies do not recommend these sensitivities for inclusion in a modified or future IRP as recommended by the ORS.

PUBLIC (REDACTED) VERSION

Q. ORS STATES THE COMPANIES PROVIDED NO BASIS FOR THE LOW EE/DSM FORECAST THAT IT USED IN THE IRP. ORS RECOMMENDS THE COMPANIES PROVIDE ADDITIONAL JUSTIFICATION OR CONSIDER OTHER APPROACHES FOR DERIVING THE LOW EE/DSM FORECAST TO BE ADDRESSED IN FUTURE IRPs. HOW DO THE COMPANIES REPLY TO THIS RECOMMENDATION?

A. As stated in the IRPs, the low energy efficiency and demand-side management scenario is "simply a 25% reduction in adoption and cost impacts of DSM programs." The reason the Companies selected this level of adoption was because few, if any, intervenors typically request to see the impacts of less savings from energy efficiency and demand-side management programs. Nevertheless, the Companies understand ORS's critique and agree—as ORS suggests—to address the appropriate level of a low energy efficiency and demand-side management case with stakeholders during the development of future IRPs. It is reasonable to further explore potential challenges to the Companies' energy efficiency assumptions that could warrant a more precise development of a low energy efficiency and demand-side management scenario. For example, it is possible, if not foreseeable, that the new federal administration could implement new codes and standards that raise the minimum energy efficiency requirements for certain consumer or commercial products and technology. If that occurs, a new baseline efficiency level would be established, and the Companies' anticipated incremental savings through utility energy efficiency programs would have to be revised downward while codes and standards would reduce the native load forecast. Other economic conditions and unexpected market changes, like a resurgence or novel pandemic, can also greatly impact the Companies' ability to effectively offer programs and the ability and desire of customers to participate. Another such challenge is "market acceptance" of certain measures and associated free-ridership of energy efficiency programs. The company agrees that the low case forecast assumptions and development should be explored in further detail in future IRPs. Witness Bak discusses these topics in his rebuttal testimony.

(H) <u>The Companies' IRPs Appropriately Address Economic Evaluation of Portfolios and Sensitivities, and the Companies Agree to Conduct a Minimax Regret Analysis to Enhance Their Analyses, as Recommended by ORS</u>

Q. PLEASE REINTRODUCE THE ACT 62 REQUIREMENTS TO PROVIDE AN ECONOMIC EVALUATION OF PORTFOLIOS AND SENSITIVITIES AS PART OF THEIR IRPS.

A. Act 62 requires utilities to provide cost estimates and analyses for the proposed resource portfolios in the plan[,]" and directs utilities to conduct "sensitivity analyses related to fuel costs . . . and other uncertainties or risks."[108]

Q. DOES ORS SUPPORT THE COMPANIES' ECONOMIC EVALUATION OF PORTFOLIOS AND SENSITIVITIES, AS PRESENTED IN THE 2020 IRPs?

A. Yes. ORS found that the Companies' economic analysis is "detailed and provides reasonable quantifications of the costs for each sensitivity for planning purposes[.]"[109]

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[108] Section 58-37-40(B)(e)(iii).
[109] ORS Sandonato Direct, at 86.

PUBLIC (REDACTED) VERSION

Q. DOES ORS PRESENT ANY RECOMMENDED IMPROVEMENTS TO BE ADDRESSED IN MODIFIED OR FUTURE IRPs?

A. Yes. ORS recommends the Companies include post in-service capital costs for new resources in the Companies' present value revenue requirement calculation for each portfolio and sensitivity. ORS recommends that this information be provided in a modified IRP in this proceeding.[110]

Q. HOW DO THE COMPANIES RESPOND TO THIS RECOMMENDATION?

A. The Companies have included post in-service capital costs for all new resources in this testimony. I have provided explanation for the inclusion these costs for all new resources in my Snider Rebuttal Exhibit 12 attached to my testimony.

Q. DOES ORS PRESENT ANY RECOMMENDED IMPROVEMENTS TO THE COMPANIES' ECONOMIC ANALYSIS AS IT RELATES TO RISK?

A. Yes. Witness Kollen suggests that the Companies should conduct a Minimax Regret Analysis of the present value revenue requirement to enhance their economic analyses.

Q. ARE THE COMPANIES WILLING TO ADOPT THE MINIMAX REGRET ANALYSIS TO QUANTIFY RISK OF ECONOMIC ANALYSIS RESULTS IN FUTURE IRPS?

A. Yes. The Companies view the use of Minimax Regret Analysis as a useful tool to help distill economic results in a digestible and consumer-friendly summary.

[110] ORS Report (DEC), at 87; ORS Report (DEP), at 88.

PUBLIC (REDACTED) VERSION

Q. DO OTHER WITNESSES ALSO RECOMMEND THE COMPANIES ADOPT A MINIMAX REGRET ANALYSIS TO QUANTIFY RISK OF ECONOMIC ANALYSIS RESULTS IN FUTURE IRPS?

A. Yes. CCEBA Witness Lucas performs an alternative Minimax Regret Analysis in his testimony.[111] However, his analysis (which the Companies to not support) and the analysis performed by ORS Witness Kollen[112] differ, with Witness Kollen's analysis viewed as the more useful and appropriate for future resource and scenario planning.

Q. HOW DO THEIR RESULTS DIFFER?

A. The ORS Report defines Regret Analysis as designed to "quantif[y] the amount by which a given portfolio exceeds the least-cost portfolio. It is a means to understand the risks associated with each portfolio given the uncertainty in future fuel and carbon prices. A portfolio with a small amount of regret across a variety of pricing scenarios is robust to a variety of futures." In Witness Kollen's Testimony, he specifies regret as representing "the PVRR amount by which each Portfolio exceeds the lowest cost Portfolio **in each fuel cost and CO_2 price case**" with the maximum regret being the most a portfolio varies from the lowest cost option in that specific scenario.[113]

In contrast, Witness Lucas measures Max Regret as the "difference between a portfolio's highest PVRR and the lowest PVRR of all the scenarios."[114] While

[111] CCEBA Lucas Direct, at 29.
[112] ORS Kollen Direct, at 9.
[113] *Id.*
[114] CCEBA Lucas Direct, at 29.

this is a minor difference, the Companies note the approach outlined by Witness Kollen would be more applicable to scenario planning as only one future can happen, while several portfolios could be applied in that one scenario.

Q. DOES THE DIFFERENCE IN THE REGRET ANALYSIS LEAD TO ANY DIFFERENCES OF QUANTIFICATION OF RISK IN THE PORTFOLIOS?

A. Yes. Witness Lucas points to the cost effectiveness of Earliest Practicable Coal Retirement Portfolio, compared to the economic coal retirement scenarios. His analysis results in the Earliest Practicable Coal Retirements Portfolio being a close second in terms of minimizing the maximum regret and highlighting a lower cost range compared to the Base Case Portfolios. The ORS results, on a combined system basis, result in the Base Planning Case without Carbon Policy being the portfolio that minimized Maximum Regret, followed by Base Planning Case with Carbon Policy. These plans also represent lower mean regret and lower regret standard deviation compared to Earliest Practicable Coal Retirements Portfolio.

Snider Rebuttal Figure 13: Combined DEC/DEP Minimax Regret Analysis Per ORS Witness Kollen's Methodology

	Base Planning without Carbon Policy	Base Planning with Carbon Policy	Earliest Practicable Coal Retirements	70% CO2 Reduction: High Wind	70% CO2 Reduction: High SMR	No New Gas Generation
Max Regret	\$2.8	\$3.1	\$4.8	\$22.5	\$17.5	\$30.3
Mean Regret	\$0.8	\$0.8	\$2.1	\$14.7	\$9.5	\$22.1
Regret Standard Deviation	\$1.0	\$1.2	\$1.7	\$4.8	\$4.8	\$4.9

While not directly related to the economic evaluation of the portfolio, it is important to reiterate, as stated in the IRP, the earliest practicable coal retirements were predicated on expeditiously replacing the coal capacity, leveraging existing infrastructure to these retiring coal sites for access to transmission, natural gas pipeline, and cooling water, while eliminating additional transmission costs to retire the coal site without replacing generation at the site. This often resulted in natural gas build outs to accelerate these coal unit retirements. These caveats must be included in any discussion involving a plan with earliest practicable coal retirements schedule, which are notably left out of Witness Lucas's assessment. The Base Cases, conversely, prudently assume that the replacements for the coal retiring coal capacity are not necessarily simply replacements at the current sites, as replacement resource options may materialize that are located elsewhere or distributed in nature.

(I) <u>The Companies' IRPs Appropriately Analyzed Customer Rate Impacts</u>

Q. IN ADDITION TO IDENTIFYING THE PRESENT VALUE REVENUE REQUIREMENT OF EACH PORTFOLIO IN THE COMPANIES' 2020 IRPs, DEC AND DEP ALSO PRESENTED AN ESTIMATED AVERAGE RESIDENTIAL CUSTOMER BILL IMPACT. WERE THE COMPANIES REQUIRED TO INCLUDE THIS METRIC IN THEIR 2020 IRPs?

A. No. The Companies were not required to include the customer bill impact analysis in their 2020 IRPs. The Companies identified that stakeholders and customers are continuing to desire how to understand not only the total cost of a plan, but how that plan is implemented over time and how those costs may be reflected in terms the customer is accustomed to in monthly bill impacts.

Q. DOES ORS SUPPORT THE COMPANIES' EFFORTS TO ANALYZE THE CUSTOMER BILL IMPACTS OF THE VARIOUS PORTFOLIOS, AS PRESENTED IN THE 2020 IRPs?

A. Yes. ORS recognizes that analyzing the average retail rate impact provides the Commission important information regarding the real-world impact of both the timing and magnitude of rate increases resulting from each of the Portfolios.[115]

Q. DOES ORS PRESENT ANY RECOMMENDATIONS OF ISSUES TO BE ADDRESSED IN MODIFIED OR FUTURE IRPs?

A. Yes.

Q. ORS HIGHLIGHTED DIFFERENCES IN THE COMPANIES' CUSTOMER BILL IMPACT ANALYSIS COMPARED TO ITS PVRR ANALYSIS. ARE THE DIFFERENCES BETWEEN THE PVRR AND THE CUSTOMER BILL IMPACT ANALYSES APPROPRIATE?

A. The differences in the analysis between the bill impacts and the PVRR analysis are appropriate. The Companies explain in further detail the differences between the assumptions in the PVRR analysis and Customer bill impact in Snider Rebuttal Exhibit 13. The Companies recognize that the methodology for providing customer bill impacts is a new concept. The Companies agree to collaborate with ORS before the next comprehensive IRP on refining and fine tuning this analysis for

[115] *See* ORS Report (DEC), at 93; ORS Report (DEP), at 93.

consistency with the rest of the IRP analysis where appropriate.

Q. WILL THE COMPANIES PLAN ON CONTINUING TO PRESENT THIS METRIC IN FUTURE IRPs?

A. As ORS has noted, the metric can be helpful to the commission in determining the cost implication from IRP portfolios relative to each other. They do not represent a full picture of absolute cost increases, but rather only the relative difference between variables measured in the IRP. To the extent ORS and the Commission continue to find this metric a useful tool to determining a plans impact to customer, the companies will continue to provide.

(J) <u>The Companies' Voluntarily Filed Their Short Term Action Plan for the Commission's Consideration Even Though the Companies are Not Required to Prepare One Under Act 62</u>

Q. DOES ACT 62 REQUIRE THE COMPANIES TO DEVELOP OR DISCUSS A SHORT-TERM ACTION PLAN ("STAP") AS PART OF THEIR IRPs?

A. No. The Companies have developed the Short-Term Action Plans for DEC and DEP as required by the NCUC. The STAP is required per Section (3) in NCUC Rule R8-60.

PUBLIC (REDACTED) VERSION

Q. ORS RECOMMENDS THE COMPANIES PROVIDE ADDITIONAL DETAILS AND STATUS UPDATES ABOUT RESOURCES INCLUDED IN THE ACTION PLAN, INCLUDING COAL RETIREMENTS, THE LINCOLN CT PROJECT, UNNAMED ENERGY STORAGE PROJECTS, NUCLEAR UPRATES, BAD CREEK UPGRADES, AND UNNAMED CHP PROJECTS. HOW DO THE COMPANIES RESPOND TO THIS RECOMMENDATION?

A. The Short-Term Action Plan, by definition, provides the successes over the past year and the Companies' plans to meet customer demand over the next five years. The Companies have included the additional requested information in this testimony as Snider Rebuttal Exhibit 14. Additionally, the Companies agree to add this revised table and associated information in the Short-Term Action Plan in future IRPs.

1. <u>The Companies Are Providing Additional Information Regarding the Darlington CT Retirement, as Recommended by ORS</u>

Q. WHAT IMPROVEMENTS DOES ORS PRESENT REGARDING THE COMPANIES' EFFORTS TO RETIRE ITS DARLINGTON CT UNITS?

A. ORS recommends that DEP provide, in a modified IRP, additional clarification regarding its plans for the retirement of the Darlington CT units, including details about any transmission impacts.

Q. DO THE COMPANIES AGREE WITH ORS'S RECOMMENDATION?

A. Yes. The Companies are providing the requested information as Snider Rebuttal Exhibit 15, which is attached to my testimony.

PUBLIC (REDACTED) VERSION

2. <u>The Companies are Providing Additional Information Regarding their CHP Assumptions, as Requested by ORS</u>

Q. WHAT DOES ORS RECOMMEND WITH RESPECT TO CHP UNITS INCLUDED IN THE COMPANIES' IRP AND SHORT-TERM ACTION PLAN?

A. ORS recommends the Companies provide additional information explaining the basis for how CHP resources were added to the Short Term Action Plan and why they were not treated as selectable resources in the economic optimization process.

Q. HOW DO YOU RESPOND TO ORS'S RECOMMENDATION?

A. The Companies agree to ORS' recommendation to provide additional information explaining the basis for how the Companies addressed CHP resources in the IRPs and STAPs. I provide this information in Snider Rebuttal Exhibit 16, which is attached to my testimony.

3. <u>DEC's Decision to Retire the Allen Units is Reasonable</u>

Q. DOES ORS PRESENT ANY RECOMMENDATIONS REGARDING THE COMPANIES' EFFORTS TO RETIRE ITS COAL PLANTS AS A RESULT OF THE RETIREMENT ANALYSIS?

A. Yes. ORS recommends DEC provide additional clarification regarding its plan for the requirement of the Allen units in a modified IRP in this proceeding. ORS requested this information in a modified IRP because these retirements were identified in the 2020 IRP and some are planned for less than a year away. The additional information requested includes details about any transmission impacts, an explanation of the steps being pursued to receive final approval from DEC and from the applicable regulatory body, as well as a timeline for conducting the activities. This information has been provided in Snider Rebuttal Exhibit 17, attached to my testimony.

(K) <u>Other Considerations – Matters Outside of these IRPs</u>

1. <u>The Commission Should Reject CCEBA's and Vote Solar's Advocacy to Require DEC and DEP to Study Fundamental Market Reforms</u>

Q. DOES ORS PRESENT ANY RECOMMENDATIONS REGARDING THE SEEM FILING AT FERC?

A. Yes. ORS highlights that the Companies' recently filed notice with the NCUC (and now with the Federal Energy Regulatory Commission) notification of the Companies' intent to establish and join SEEM. SEEM is a region-wide, automated, intra-hour platform that matches buyers and sellers with the goal of more efficient bilateral energy trading and assumes utilization of unused transmission capacity to achieve cost savings for customers in the Southeast.[116] ORS recommends that the Companies provide details regarding the status of the SEEM, details regarding important current and planned activities, and information regarding the monetary benefits that have been achieved by implementation of the SEEM.[117] ORS points to PacifiCorp's routine updates to its state commissions on that utility's participation in the Western Energy Imbalance Market ("EIM") as a model for the type of information that ORS recommends the Companies include in future IRPs.

Q. DO THE COMPANIES AGREE TO ORS'S RECOMMENDATIONS?

A. Yes. The Companies agree to provide the Commission with an update on their participation in SEEM in future IRPs filed with the Commission. However, SEEM

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[116] See ORS Report (DEC), at 99; ORS Report (DEP), at 98-99.
[117] See ORS Report (DEC), at 100; ORS Report (DEP), at 99.

is not yet approved so the only update the Companies could provide on this issue in a modified IRP in these dockets is that the Southern Company Services, Inc., on behalf of the Companies and 12 other SEEM members, filed the joint Application for approval of the SEEM Agreement for FERC approval on February 12, 2021.[118] The SEEM application remains pending before FERC.

I would also note for the Commission's general information that SEEM is designed to better enable "non-firm" real-time energy exchanges at the sub-hourly or 15-minute level. In contrast, the core objective of the Companies' IRP modeling and planning is to evaluate how to reliably and cost effectively meet customers hourly demand each hour of each day over a much longer 15 year planning horizon. IRPs meet this hourly demand and associated winter peak demand with firm existing resources and projected future firm resources coming onto the system. I raise this distinction to highlight that the sub-hourly non-firm real-time energy exchange opportunities that will be enabled under SEEM offers the potential to help reduce real time energy costs but does not represent firm capacity. This limits the impact SEEM participation may have on the Companies' IRP. Once SEEM is approved and the participating utilities gain experience with the resultant non-firm energy flows and resulting savings, potential impacts of SEEM participation to the IRPs will be discussed in future IRPs The Companies will work with ORS to ensure that the information provided in future IRPs is appropriate and responsive to this recommendation.

[118] *S. Co. Servs. Inc.,* Southeast Energy Exchange Market Agreement, Docket No. ER21-1111-000 (filed Feb. 12, 2021).

PUBLIC (REDACTED) VERSION

Q. DO ANY OF THE ADVOCACY GROUP WITNESSES COMMENT ON SEEM OR OTHER WHOLESALE MARKET DESIGN ISSUES?

A. Yes. CCEBA Witness Lucas argues that the Companies' IRPs "overlook the benefits of regionalization" and advocates that 1) the Companies should proactively seek changes that would allow the Companies to file joint IRPs between DEC and DEP and plan and operate its two companies as a single utility suggesting that this would "minimize[] costs for all its customers"; and 2) argues that the Companies should study the potential benefits of broader regionalization through wholesale market structures such as an EIM or RTO, which Witness Lucas suggests could potentially deliver more significant benefits than SEEM.[119]

Vote Solar Witness Fitch similarly argues that the Commission should require the Companies to "prepare an action plan for implementing joint capacity planning between the Companies," including evaluating any required changes to the joint dispatch agreement, any anticipated required regulatory approvals, and a projection of a realistic timeline for implementation.[120] Similar to CCEBA Witness Lucas, Witness Fitch also recommends that the Commission direct the Companies to prepare an analysis comparing the benefits, including but not limited to direct ratepayer benefits and climate-related risk mitigation, of several regional coordination configurations, including but not limited to an EEM, and EIM, and an RTO.[121] However, Witness Fitch goes even further to suggests that this required

[119] CCEBA Lucas Direct, at 103.
[120] Vote Solar Fitch Direct, at 59.
[121] Vote Solar Fitch Direct, at 60.

analysis should be conducted by a third-party consultant that is mutually agreeable to the Companies, Commission, and ORS.

Q. HOW DO YOU RESPOND TO WITNESS LUCAS'S AND WITNESS FITCH'S RECOMMENDATIONS THAT THE COMPANIES SHOULD BE REQUIRED TO MODIFY THE JOINT DISPATCH AGREEMENT AND UNDERTAKE JOINT CAPACITY PLANNING?

A. The Companies obtained FERC approval of the Joint Dispatch Agreement ("JDA")[122] between DEC and DEP in 2012, as part of the merger between Duke Energy Corporation and Progress Energy Corporation. First and foremost, the Companies assert that the JDA cannot be changed in this South Carolina IRP docket. If the Commission wishes to change its prior orders and depart from regulatory conditions that were foundational to such merger, it should do so either in the South Carolina merger docket or independently noticed in a separate proceeding to the parties in the merger docket, Docket No. 2011-158-E, recognizing that changes would also have to be approved at FERC and by the NCUC.

The JDA enables DEC and DEP to transfer incremental economic energy between DEC's and DEP's generating fleets from the system with lower marginal costs to displace higher cost system generation on the other system. More precisely, the JDA is an opportunistic, economic, incremental-cost energy transfer tool, which relies on hour-by-hour, as-available, non-firm, curtailable transmission and does

[122] Joint Dispatch Agreement, effective July 2, 2012, between Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (formerly known as Carolina Power & Light Company) on file with the Federal Energy Regulatory Commission in Docket No. ER12-1338-000.

not reduce availability of firm transmission for long-term wholesale transactions of other network transmission customers.

The Companies do not dispute that the JDA does not set up a joint balancing authority or operate as a single utility nor does it in any way facilitate joint capacity planning by DEC and DEP. Pursuant to both the NCUC's[123] and this Commission's[124] regulatory approvals of the Duke-Progress Merger, DEP and DEC continue to operate as separate BAs and utilities, and each is responsible for its own independent resource planning and operations. Indeed, Section 4.1 of the regulatory conditions, as approved by the NCUC and by this Commission, explicitly require that the Companies not transfer any rights to generation or transmission facilities between DEC to DEP or to construct generation or transmission facilities for the benefit of the other.[125]

Resource planning—how the Companies plan to meet their load obligations for the next 15 years—needs to be rooted in the legal and regulatory standards and requirements in place at the time the IRP is developed and should be limited by "foreseeable conditions," as recognized by Act 62. At this time, there is no regulatory basis for the Companies to evaluate planning and operating their systems

[123] *See Order Approving Merger Subject to Regulatory Conditions and Code of Conduct*, N.C.U.C. Docket Nos. E-2, Sub 998 and E-7, Sub 986 (June 29, 2012).
[124] See generally Commission Docket No. 2011-158-E.
[125] Regulatory Condition No. 4.1, which provides that "DEC and DEP acknowledge that the Commission's approval of the merger and the transfer of dispatch control from DEP to DEC for purposes of implementing the JDA and any successor document is conditioned upon the JDA never being interpreted as providing for:
(a) A single integrated electric system
(b) A single BAA, control area, or transmission system
(c) Joint planning or joint development of generation or transmission
(d) DEC or DEP to construct generation or transmission facilities for the benefit of the other
(e) The transfer of any rights to generation or transmission facilities from DEC to DEP to the other, or
(f) Any equalization of DEC's and DEP' production costs or rates."

jointly in the context of an IRP Docket, as recommended by Witnesses Lucas and Fitch and it is not foreseeable that this would change between now and the Companies' next comprehensive IRP filings scheduled next year.

Simply put, even if the Commission were to desire for the Companies to undertake a review of the Companies' operations under the JDA or to consider the significant regulatory complexities and implications of combining the DEC and DEP BAs, the IRP proceeding would not be the appropriate forum for imposing such requirements. The Companies believe that the Commission should reject the Advocacy Groups desires for the Companies to undertake such comprehensive, time consuming and expensive regulatory and analytical studies. It is important to recognize that while the IRP touches on many aspects of the utility business, an IRP proceeding was never intended to be, nor authorized to be, the procedural mechanism for addressing all emergent regulatory or legislative energy issues

Q. IS WITNESS LUCAS CORRECT IN HIS VIEW THAT THE IRPs DO NOT APPROPRIATELY TAKE IMPORT CAPACITY FROM NEIGHBORING BAs INTO CONSIDERATION?

A. No. The IRP process seeks to balance supply and demand for regulated service territories and relies on the interconnected regional energy system to reduce planning reserve margin by recognizing the potential for neighboring assistance at time of peak due to regional diversity of load and resources. To that extent, a broader regional view does impact the resource planning process. This can be seen in the Companies' Resource Adequacy Study which shows planning reserves would be much higher if the Companies were an "island" rather than being connected to neighboring utilities.

Q. WHAT IS YOUR VIEW REGARDING WITNESS LUCAS'S AND WITNESS FITCH'S SECOND RECOMMENDATION THAT THE COMMISSION SHOULD REQUIRE THE COMPANIES TO STUDY ALTERNATIVE EIM OR RTO WHOLESALE MARKET STRUCTURES AS PART OF THE COMPANIES' FUTURE IRPs?

A. As further discussed by Witness Santoianni, Vote Solar and CCEBA ask this Commission to invade the space already occupied by the General Assembly. While the Commission would undoubtedly have much work to do if the State of South Carolina made the decision to enter a different market structure, that involvement would only occur if the state legislators make a decision to move in that direction. Notably, the Companies asked CCEBA in discovery what actions the Commission should take in this proceeding in response to Mr. Lucas's testimony relating to energy market reforms in South Carolina in light of the fact that the General Assembly is reviewing these issues. CCEBA responded that it "has no recommendations at this time."[126]

[126] CCEBA Response to DEC/DEP Interrogatory 1-21, attached as Snider Rebuttal Exhibit 18.

PUBLIC (REDACTED) VERSION

2. Vote Solar Recommendation to Procure Modeling Licenses for Intervenors Should be Rejected

Q. VOTE SOLAR WITNESS FITCH RECOMMENDS THAT THE COMMISSION ORDER THE COMPANIES TO PROCURE LICENSES FOR MODELING SOFTWARE TO "ENHANCE TRANSPARENCY BETWEEN THE COMPANIES, COMMISSION, AND STAKEHOLDERS."[127] DO THE COMPANIES AGREE?

A. No. While the Companies recognize that the Commission found a similar recommendation appropriate in the recent DESC IRP Order, the Companies strongly oppose requiring the Companies and, ultimately, customers to pay for licenses for Advocacy Groups that oppose the Companies' IRPs to advance their interests.

Q. PLEASE PROVIDE CONTEXT FOR THIS RECOMMENDATION.

A. In the recent DESC IRP proceeding, the Commission ordered DESC to acquire and pay for licenses that would allow interested intervenors access to the capacity expansion modeling software DESC will use for future IRP modeling so that intervenors can perform their own alternative modeling runs in the same software package as DESC. The Commission's ruling was a response to intervenor testimony arguing that the cost associated with a PLEXOS license—the platform DESC selected for future IRPs—is prohibitively expensive, costing several hundred thousand dollars. Witness Fitch advocates for the same approach in the instant proceeding, asking the Commission to require the Companies to acquire and

[127] Vote Solar Fitch Direct, at 54.

pay for licenses that permit intervenors to use the Companies' modeling software in the interest of promoting transparency.

Q. CAN YOU EXPLAIN WHY THE COMPANIES OBJECT TO THIS PROPOSAL?

A. First, although I am not a lawyer, I understand that imposing such an affirmative requirement for the Companies to fund the development of positions adverse to their interests goes well beyond the bounds of traditional discovery under both the Commission Rules and the South Carolina Rules of Civil Procedure. Act 62 provides for "*reasonable* discovery . . . to assist parties in obtaining evidence concerning the integrated resource plan, including the reasonableness and prudence of the plan and alternatives to the plain raised by intervening parties[.]"[128] While Act 62 does not set finite parameters on the types of discovery that could be deemed "reasonable," ordering this type of access to the Companies' modeling software would impose an unprecedented and unreasonable burden on the Companies and their customers.

In particular, the Companies and their rate-payers should not be required to cover the costs of intervenors' participation in these dockets. While ORS is granted special authority to make inspections, audits, and examinations of public utilities under South Carolina law,[129] other intervenors are limited to the traditional rights of parties. In no scenario could a court order the Companies to cover the cost of a Westlaw license for performing legal research so that intervenors may participate

[128] S.C. Code Ann. § 58-37-40(C)(1) (emphasis added).
[129] S.C. Code Ann. § 58-4-50(2).

in these dockets, and the same is true for covering the cost of a modeling license.

Q. CAN YOU DISTINGUISH THE DESC ORDER FROM THE FACTS AT ISSUE IN THE COMPANIES' IRPs?

A. Yes. DESC was also in a unique position because it did not use industry-recognized capacity expansion modeling software in preparing its 2020 IRP, a deficiency that the Commission found did not comply with industry best practice. DESC informed the Commission that it had already selected the PLEXOS model for use across all of its operating units going forward. Intervenors objected to the use of PLEXOS on multiple grounds, including the extreme cost for intervenors to gain access, poor user interface, modeling limitations, as well as purported "transparency barriers" inherent to PLEXOS that render it difficult to export inputs and outputs in useable format.[130] The Commission's Order was thus a direct reaction to significant accessibility and transparency concerns. In addition to mandating that DESC cover the cost of licensing, the Commission also required DESC to obtain input from stakeholders and the Commission on the selection and implementation of capacity expansion modeling software, in effect directing DESC to reconsider its selection of PLEXOS.

Unlike DESC, the Companies have selected Encompass, a lower cost capacity expansion and production cost modeling software that has not been the subject of similar criticism.

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[130] Order No. 2020-832, at 28, *In re South Carolina Energy Freedom Act (House Bill 3659) Proceeding Related to S.C. Code Ann. Section 58-37-40 and Integrated Resource Plans for Dominion Energy South Carolina, Incorporated*, Docket No. 2019-226-E (2020).

PUBLIC (REDACTED) VERSION

Q. VOTE SOLAR COUCHES ITS REQUEST IN TERMS OF "PROMOTING TRANSPARENCY." DO THE COMPANIES ALREADY VOLUNTARILY MAKE REASONABLE EFFORTS TO PROMOTE TRANSPARENCY AROUND THEIR IRPs?

A. Absolutely. As I addressed in my direct testimony and reiterated earlier in this testimony, the Companies have made extensive, good faith efforts to engage with stakeholders regarding the 2020 IRPs and plan to continue to do so in the future. As I also mentioned, the Companies produced over 3,200 separate pieces of information on their IRPs in discovery. In addition, the Companies setup an FTP site and uploaded approximately 350 MB of data and supporting documents for the IRP and Resource Adequacy Study, as well as provided multiple opportunities for stakeholders to engage with the Companies throughout the development of the IRP. These voluntary good faith efforts to engage with stakeholders are reasonable and further support the Companies' opposition to this unreasonable recommendation.

In addition, it is an oversimplification to suggest that simply procuring a license would allow intervenors unfettered access to test the Companies' assumptions and run competing models with alternate inputs. Capacity expansion and production cost modeling software is complex. Although the Companies agree that Encompass has a more user-friendly interface than PLEXOS, it took the Companies' experienced modelers several days in vendor training followed by approximately six months of engaging with the product daily to become proficient in using the software to make successful model runs. Encompass also requires enhanced hardware capabilities, and attempting to run a simulation model would

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likely take 20-30 hours on a typical PC. In short, effectively engaging with the Encompass tool requires significant investments in time and resources, not just access to a license and there is no basis for the Companies to become entangled with these efforts.

Finally, to promote further transparency, the Companies have been and remain willing to share inputs used with intervenors through the stakeholder process. The Companies believe this is a more appropriate path to achieve Witness Fitch's goal of engaging with the models. Given the obstacles to use and the Companies' willingness to transparently share input/output data, it would be inappropriate to ask the rate payer to cover the cost of these software licenses for intervenors.

Q. DOES ORS OR ANY OTHER INTERVENOR MAKE A SIMILAR ARGUMENT?

A. No. Vote Solar is the only party that argues that the Companies should be obligated to pay for software licenses to allow them to develop alternative plans and recommendations to those supported by the Companies.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.